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GENERATION OF STEAM USING LOW-GRADE FUELS AND FIELD PRODUCED WATER FOR IN-SITU OIL RECOVERY

FINAL REPORT

Energy, Mines and
Resources Canada

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Dr. D. Faurschou
Department of Energy, Mines & Resources
555 Booth Street
Ottawa, Ontario
K1A 0G1

Dear Dr. Faurschou:

Subject: Generation of Steam Using Low-Grade Fuels and Field Produced Water For In-Situ Oil Recovery

We are pleased to submit herewith our final report summarizing the findings of the above noted study. It provides a review of current practice in Western Canada with respect to steam generation for oil recovery and a detailed investigation of promising new technologies which may offer some significant advantages over existing systems. A perspective is given on the possible costs associated with these new processes and recommendations are provided for research and development work required to promote their commercialization.

We have appreciated this opportunity to serve you and look forward to assisting CANMET with future developments in this area.

Sincerely,

Clyde W. Fulton

Clyde W. Fulton, P.Eng.
Project Manager

CWF/rms
Encl.

201 pp

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CHAPTER 1
INTRODUCTION

BACKGROUND

The preponderance of steam injection oil recovery projects in western Canada utilize conventional, once-through, oil or gas-fired steam generators. As an industry average, approximately one barrel of crude oil (or natural gas equivalent) out of every three barrels produced by steam injection is reportedly consumed as fuel in the steam generation process (Reference 1-1).

In addition, conventional steam generators require significant quantities of soft, oil-free water as feedwater. Two to four barrels of water (as steam) must typically be injected per barrel of oil recovered. This frequently taxes the often scarce supplies of fresh water available in the oil producing regions of western Canada sufficiently that serious consideration must be given to reuse of the large quantities of brackish produced water generated with the oil production. While the technology for produced water treatment and reuse in conventional steam generators has been successfully demonstrated, the process is relatively sophisticated and costly.

Alternative steam generation technologies have been demonstrated or proposed for oil recovery EOR applications which are capable of burning low grade solid fuels and/or reusing produced water as feedwater with minimal pretreatment. Processes have also been developed which inject both steam and combustion gases into the oil-bearing formation, thereby reducing the atmospheric emission of air pollutants and reportedly improving oil recovery. In view of the limited long-term availability of oil and natural gas, their intrinsic value as feedstock to a host of other petrochemical processes, and the projected escalation in their price, the development of steam generation technology which is capable of burning less-expensive and more-abundant solid fuels is considered advantageous. Likewise, the development of alternative processes which inject combustion gases and which are capable of reusing produced water without significant pretreatment, may further improve the economics and environmental acceptance of steam injection for oil recovery.

The Canada Centre for Mineral and Energy Technology (CANMET), Energy Mines and Resources Canada, is interested in promoting the development of such alternative steam generation technologies for application in Canadian oil recovery projects. To evaluate which technologies are most likely to yield future technical and economic success, and to identify research and development requirements necessary for the commercialization of the most promising technologies, CANMET sponsored this comparative assessment of alternative steam generation processes. The specific objectives of the study are outlined below.

OBJECTIVES

The objectives of this study can be summarized as follows:

1. To assess the nature of field-produced or recycle water from thermal recovery operations in western Canada.

2. To report on the status of technology for the generation of steam for oil field injection using solid fuels and/or field-produced water with minimal pretreatment.

3. To assess the potential for application of these technologies to thermal recovery of oil in western Canada (specifically wet oxidation and Thermosludge steam generation).

4. To assess the feasibility and advantages of directly injecting steam and combustion gases into the oil-bearing formation. The option of oxygen as well as air to support combustion is to be considered, and the effects of combustion products on the reservoir, on the produced oil, and on recovery efficiency are to be addressed.

5. To review gas (solvent, flue gas) - steam injection methods and identify potential preferred applications in western Canada.

6. To make recommendations for research and development work on submerged or other combustion technology for application to the oil industry.

7. To identify industrial partners for share-cost funding of recommended laboratory or field studies.

METHODOLOGY

The study was conducted in essentially two phases. Phase One involved the development of a data base and identification of steam generation technologies which fulfilled the criteria for further evaluation, while Phase Two entailed the detailed technology review.

The study was initiated with a literature review to establish the current status of thermal recovery projects in western Canada with respect to the steam generation equipment, fuels, and feedwater specifications commonly used and produced water characteristics typically encountered. This information is presented in Chapter 2.

Alternative steam generation technologies currently at bench, pilot or commercial stages of development which fulfilled any of the three following criteria were then identified:

1. Those capable of burning solid fuel.
2. Those able to reuse produced water with little or no pretreatment.
3. Those which inject combustion gases to the oil-bearing formation.

A preliminary assessment of all identified technologies was then prepared and the processes were screened to select those with the greatest potential for future development and application to thermal oil recovery. The processes selected for detailed evaluation included:

1. Thermosludge steam generation
2. Fluidized bed combustion
3. Wet oxidation
4. Vapor Therm
5. Downhole steam generation

A detailed evaluation of each process was then conducted. This involved establishing contacts and holding meetings with individuals and firms responsible for research, development and commercial application of each of the selected technologies. Detailed process information was gathered concerning process design, feedwater pretreatment requirements, chemical and utility requirements, energy conversion efficiency, environmental implications, etc. Process equipment was inspected, where possible, and data regarding the demonstrated performance and stage of development of each process was compiled. This information is presented in Chapter 3.

Order-of-magnitude capital and operating cost estimates were prepared for each of the technologies considered. These were compared to a "base case" of a conventional gas or crude oil fired once-through steam generator to obtain a perspective on the economics associated with these alternative technologies. This information is presented in Chapter 4.

Several of the processes considered in this study inject combustion gases into the oil-bearing formation with the product steam. As part of this study, Dr. S. M. Farouq Ali, professor of Petroleum Engineering, University of Alberta, investigated the reservoir effects of steam plus combustion gas injection. His findings are reported in Appendix A. Also included in Appendix A is a review of the possible applications of solvent-steam and flue gas-steam injection processes in western Canada.

Areas in which further work is required were identified and are outlined in Chapter 5. Also identified are the names of firms and individuals contacted regarding possible interest in participation in share-cost funding of future laboratory or field studies to demonstrate alternative steam generation technologies. Contacts with process vendors responsible for development and/or marketing of each technology considered in this study are also provided.

REFERENCE

1-1 Davis, J.S., Young, W.W., and Lyons, C.J.; "Use of Solids Fuel Possible for Field Steam Generation" Oil and Gas Journal, pp. 129-134, 1981 June 8.

CHAPTER 2
CURRENT PRACTICE

INTRODUCTION

Thermal techniques have been applied both to recover heavy oils and bitumen which are too viscous to flow in their naturally occurring state, and to enhance the recovery of lighter oils in cases where reservoir pressure has been depleted leaving significant quantities of oil behind, which cannot be produced by conventional primary means. In general, in-situ thermal recovery involves heating the reservoir to reduce the oil viscosity to the point that it flows sufficiently well for recovery by conventional pumping methods.

The two most common thermal techniques of oil recovery currently in various stages of field piloting in western Canada are in-situ combustion and steam injection. The former uses in-place oil deposits as fuel and formation water or recycled produced water to control combustion temperatures. The latter normally uses surface steam generation equipment fired by natural gas or liquid fuels and requires a higher quality feedwater source. Several modifications of these processes are also used, such as the Amoco COFCAW (Combination of Forward Combustion and Waterflood) recovery process and cyclic pressurization and depressurization of the reservoir with steam as used by Shell at their Peace River pilot project. Petro Canada has also experimented with an electric preheat/steamflood process at Surmount. Only the steam injection processes are addressed in this report.

Steam injection may be categorized further as either cyclic steam stimulation or a continuous steamflood process. Steam stimulation (also referred to as huff and puff) is a cyclic process of steam injection followed by the production of oil and associated fluids from each well. A typical cycle involves injection of steam for several weeks (huff), a soak period of some days to allow the heat and pressure of injection to dissipate into the reservoir, and finally a production (puff) phase of some months in which oil and fluids flow back and are pumped from the well. The production cycle is terminated when the temperature of the fluids drops to the point that low oil recovery rates are achieved. The entire cycle is then repeated.

In the steamflood (also referred to as steam drive) process, specific wells within a field pattern are designated as injection wells, while others are dedicated to production. In this process, the reservoir is normally preheated and produced by steam stimulation prior to converting to a steam drive mode. Once thermal communication has been established between wells, steam is continuously injected to designated wells providing a driving force for the reservoir fluids which are continuously produced from neighbouring wells.

Formation water and condensed steam are co-produced with the oil and are referred to as produced water. Water to oil ratios in the Cold Lake region of Alberta are typically in the order of 2:1, whereas values as high as 10:1 are experienced in some of the heavy oil producing regions of California. The produced water typically contains high concentrations of emulsified oil, solids, and dissolved salts and minerals. As such, it is generally unsuitable for direct surface disposal or generation of steam by conventional methods without pretreatment.

This chapter reviews the conventional steam generation process, the characteristics of produced waters, and the treatment requirements and limitations for reuse of produced water in conventional steam generation equipment.

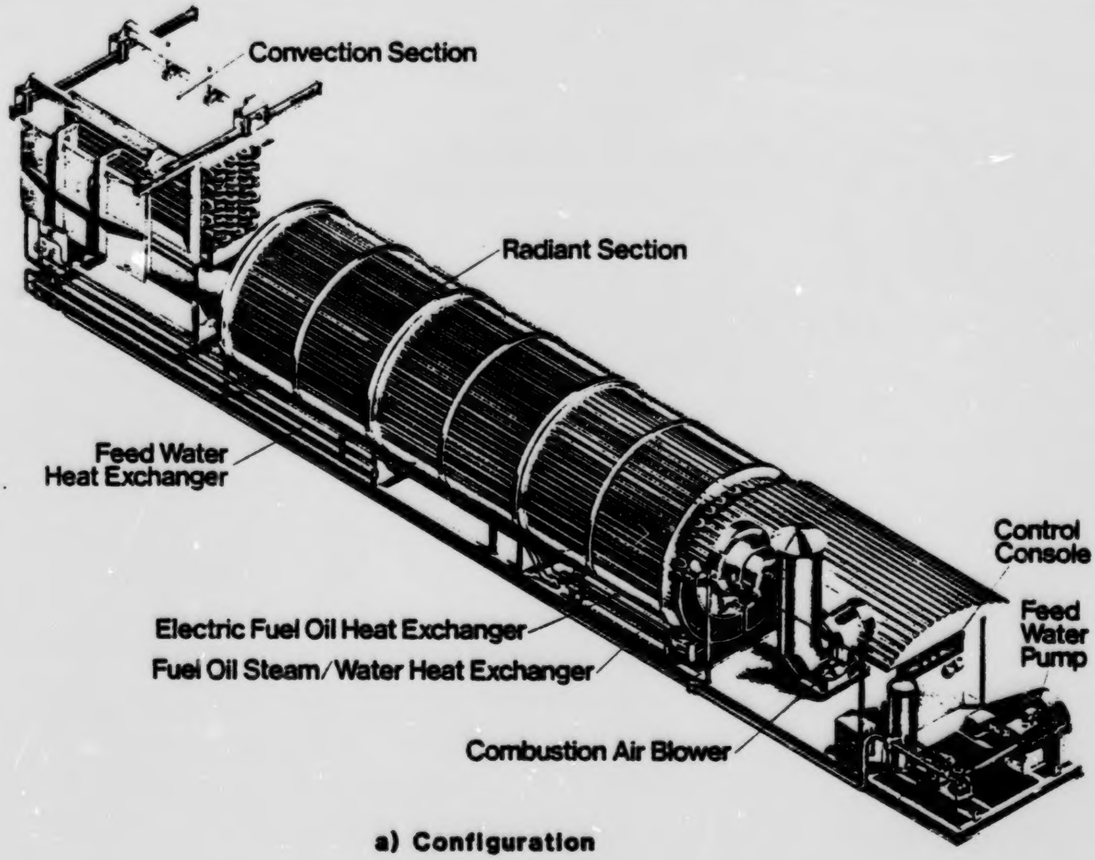
CONVENTIONAL STEAM GENERATION

The preponderance of steam injection projects in western Canada utilize conventional once-through gas or oil-fired steam generators to produce wet product steam, typically of about 80 percent quality.

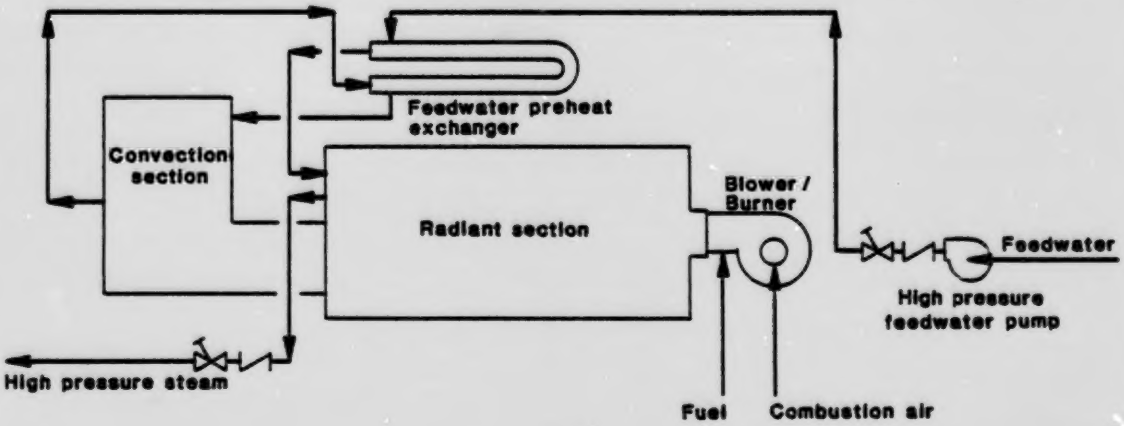
As illustrated in Figure 2-1, the once-through steam generator is characterized by a long, horizontal section in which direct radiant heat transfer from the flame predominates and a vertical section where convection is the principal mechanism of heat transfer from the flue gases to the tube bundle. Preheated boiler feedwater first passes through the convection section and then through a heat exchanger to preheat the feedwater. The water then enters the radiant section where horizontal water tubes are arranged in a serpentine configuration inside the cylindrical refractory wall. A feedwater pump is used to provide forced circulation through the steam generator, with the water making a single pass and leaving as a two phase steam/water mixture. A sufficiently high water/steam ratio is maintained at the steam generator outlet to ensure complete, continuous wetting of the tube walls.

Since these units are typically designed to produce about 80 percent quality steam, they are capable of handling feedwaters with relatively high dissolved solids concentrations, provided the solids are still soluble at the concentrations present in the condensate film. The wet steam, containing all of the dissolved solids originally present in the feedwater concentrated into the liquid phase, is then injected to the oil-bearing formation, eliminating the need for a blowdown stream from the steam generator.

Once-through steam generators are manufactured by several vendors (primarily Struthers Thermoflood Corp., C.E. Natco,


Convection Section
Radiant Section
Feed Water Heat Exchanger
Control Console
Feed Water Pump
Electric Fuel Oil Heat Exchanger
Fuel Oil Steam/Water Heat Exchanger
Combustion Air Blower

a) Configuration


Feedwater preheat exchanger
Convection section
Radiant section
Blower / Burner
Feedwater
High pressure feedwater pump
High pressure steam
Fuel
Combustion air

b) Schematic

Figure 2-1
ONCE-THROUGH STEAM GENERATOR

and Thermotics Inc.) and are commercially available in sizes ranging from 1.5 to 44 MW (5 MM BTU/hr to 150 MM BTU/hr) and pressures up to 17 MPa (2500 psi). A somewhat modified design of the once-through generator, developed by Mitchell Engineering in Great Britian and marketed by Babcock and Wilcox in Canada is called a "Coil Boiler" and utilizes a vertical, helical water-tube coil as a heat transfer surface. It is otherwise similar in design concept to the "hairpin" style steam generators described above.

Overall energy conversion efficiencies for conventional once-through steam generators are typically in the order of 85 percent, including fuel and electrical power consumption for pumps, blowers, etc.

Stringent air quality regulations in California, where this equipment is in widespread use, have necessitated that these generators be equipped with emission control devices to restrict the discharge of SO_2 and NO_x. This has included burner redesign to reduce the production of NO_x and the installation of add-on scrubbers to remove SO_2 from the flue gas. In western Canada, where there is a much lower density of heavy oil development, and most steam generators are gas rather than crude-fired, the implementation of these measures has not been necessary to date.

The feedwater quality objectives for once-through steam generators are presented below:

Total Hardness	<0.5 mg/L as $CaCO_3$
Silica	<50 mg/L
Oil	<1 mg/L
Total Dissolved Solids (TDS)	<8000 mg/L
Suspended Solids	0
Iron	<0.05 mg/L
Oxygen	<0.04 mg/L

The prime requisite is that the feedwater contain essentially zero hardness, less than 1 mg/L of free oil, silica of less than 50 mg/L and a maximum of 0.05 mg/L of iron. All traces of free oxygen must also be removed.

Considerable uncertainty exists as to the maximum total dissolved solids content which can be tolerated in a once-through steam generator. From strict solubility considerations, sodium chloride concentrations approaching 50 000 mg/L in the feedwater are theoretically possible at an outlet steam quality of 80 percent. Yet, there is very little operating experience with dissolved solids concentrations above 8000 mg/L. While one manufacturer has conducted short term testing of a once-through steam generator on a feedwater with a dissolved solids content of 24 000 mg/L, most do not recommend feedwater TDS concentrations in excess of 8000 mg/L. The major concern appears to be that transient conditions within the boiler may create hot-spots on the water tubes leading to scale deposition and premature burnout due to incomplete wetting of the walls. Furthermore, as TDS content increases, it becomes increasingly difficult to achieve the objective of zero hardness in the feedwater, from a water treatment perspective.

It should be recognized that the feedwater quality objectives presented above are vendor recommendations and that some of these values are routinely exceeded in actual practice. For instance, some California installations have reported the successful use of feedwaters with several mg/L of residual hardness, provided EDTA chelant is added to control scale deposition. Feedwater silica concentrations in excess of 250 mg/L have also been reported using dispersants and/or by maintaining a pH in excess of 12.0 in the water phase of the high pressure steam to prevent silica deposition. However, complete hardness removal is critical with high silica concentrations, as hardness leakage from the water softeners has reportedly led to rapid scaling problems in such instances (Reference 2-1).

PRODUCED WATER CHARACTERISTICS

A survey of heavy oil/oil sands commercial and pilot facilities in Canada, the United States, and Venezuela utilizing thermal recovery methods was undertaken to examine produced water characteristics. The results of the survey are summarized in Table 2-1. It clearly demonstrates that the composition of produced water varies considerably from location to location.

As outlined in the previous section, the principal constituents which affect the treatment of produced water for reuse in steam generation are hardness, silica, oil, and total dissolved solids. Reported hardness concentrations range from as low as 141 mg/L at Esso, Cold Lake to a high of 1200 mg/L at Lagoven, Venezuela. Silica varies between 98 mg/L, as reported at Shell, Peace River and 380 mg/L at Mobil, South Belridge. Oil is reported by Texaco, San Ardo to be 98 mg/L, whereas Esso and Lagoven have observed much higher levels of 2000 mg/L and 5000 mg/L respectively. Total dissolved solids concentrations range from a low of 844 mg/L at Getty, Kern River to 22 000 mg/L at Lagoven, Venezuela.

The concentration range of primary constituents in produced water from western Canadian thermal recovery operations is presented below, based on information provided by the operators identified in Table 2-1.

Total Hardness	140 - 720 mg/L as $CaCO_3$
Silica	100 - 250 mg/L
Oil	100 - 2000 mg/L
Total Dissolved Solids (TDS)	6000 - 15 000 mg/L
Suspended Solids	70 - 1000 mg/L
Iron	0.1 - 0.8 mg/L

TABLE 2-1
SURVEY OF PRODUCED WATER CHARACTERISTICS

PARAMETER	ESSO RESOURCES LTD. COLD LAKE, ALBERTA	SUNCOR, INC. FORT KENT, ALBERTA	BP CANADA LTD. MARGUERITE LAKE, ALBERTA	SHELL CANADA LTD. PEACE RIVER, ALBERTA	GETTY OIL LTD. KERN RIVER, CALIFORNIA	TEXACO SAN ARDO, CALIFORNIA	MOBIL OIL SOUTH BELRIDGE, CALIFORNIA	SHELL OIL LTD. McKITTRICK, CALIFORNIA	CONOCO INC. CAT CANYON, CALIFORNIA	LAGOVEN OIL ORINOCO HEAVY OIL BELT, VENEZUELA
Ca mg/L	48	180	150	120	NR	NR	188	109	75	450
Mg mg/L	5	65	75	35	NR	NR	27	56	20	100
Na mg/L	1 743	4 500	4 000	2 252	215	2 105	3 300	2 500	1 541	8 000
Total hardness mg/L $CaCO_3$	141	720	684	444	132	162	580	503	270	1 200
CO_3 mg/L	15	0	15	0	15	0	NR	45	0	0
HCO_3 mg/L	304	440	750	1 558	292	255	NR	883	789	1 000
SO_4 mg/L	111	525	600	379	53	410	NR	180	167	15
Cl mg/L	3 094	7 253	6 000	2 569	199	2 980	4 800	3 517	2 000	12 500
S mg/L	40	.01	NR	NR	0	10	NR	0	NR	0
B mg/L	10	NR	37	NR	1	NR	NR	15	NR	NR
SiO_2 mg/L	250	140	150	98	125	130	380	121	268	NR
Fe mg/L	0.8	0.1	NR	< 0.1	0.1	1.0	NR	NR	1.0	NR
TDS mg/L	6 015	15 000	10 000	7 010	844	6 115	13 000	7 000	4 862	22 000
pH	8.0	7.5	7-9	7.1	8.3	6.8	7.2	NR	7.4	7.5
Conductivity µmhos/cm	NR	20 000	NR	11 100	1 190	NR	17 000	8 360	NR	NR
Suspended solids mg/L	68	450	500 - 1 000	NR	NR	69	NR	NR	5	5
Insoluble or suspended oil mg/L	400 - 2 000	100 - 200	300 - 1 000	NR	200	96	140	NR	NR	5 000

NR - Not Reported

In addition to the variation in produced water composition from location to location, variations with respect to time in the in-situ recovery process at a given location have also been observed. In a steam stimulation process, a high percentage of relatively high quality (i.e., low TDS) steam condensate is frequently produced in the early stages of the production phase, whereas a higher concentration of brackish (i.e., higher TDS) native formation water is observed in the latter part of the cycle. In addition, increases in TDS, hardness, and silica are frequently observed in subsequent production cycles on the same well. The recycling of hot, high TDS water to the formation appears to result in the dissolution of native salts and minerals. Although not well documented in the literature, two or three-fold increases in produced water TDS concentrations over the lifetime of an oilfield have been predicted for some thermal, in-situ recovery projects.

PRODUCED WATER REUSE

To enable produced water to be reused as feedwater to a conventional once-through steam generator, it must normally be treated for the removal of essentially all oil and hardness and frequently a reduction in silica content. A process for the treatment of produced water, characteristic of that occurring in western Canada, to once-through steam generator feedwater quality is illustrated schematically in Figure 2-2. Such a process is currently used by Esso Resources for reuse of produced water generated at their Leming pilot project, at Cold Lake, Alberta.

To reduce oil concentrations to a level low enough to prevent interference with the downstream processes, the deoiling sequence is normally carried out in three stages; gravity separation in a skim tank, induced gas flotation (IGF) and pressure sand filtration. The skim tank - IGF combination

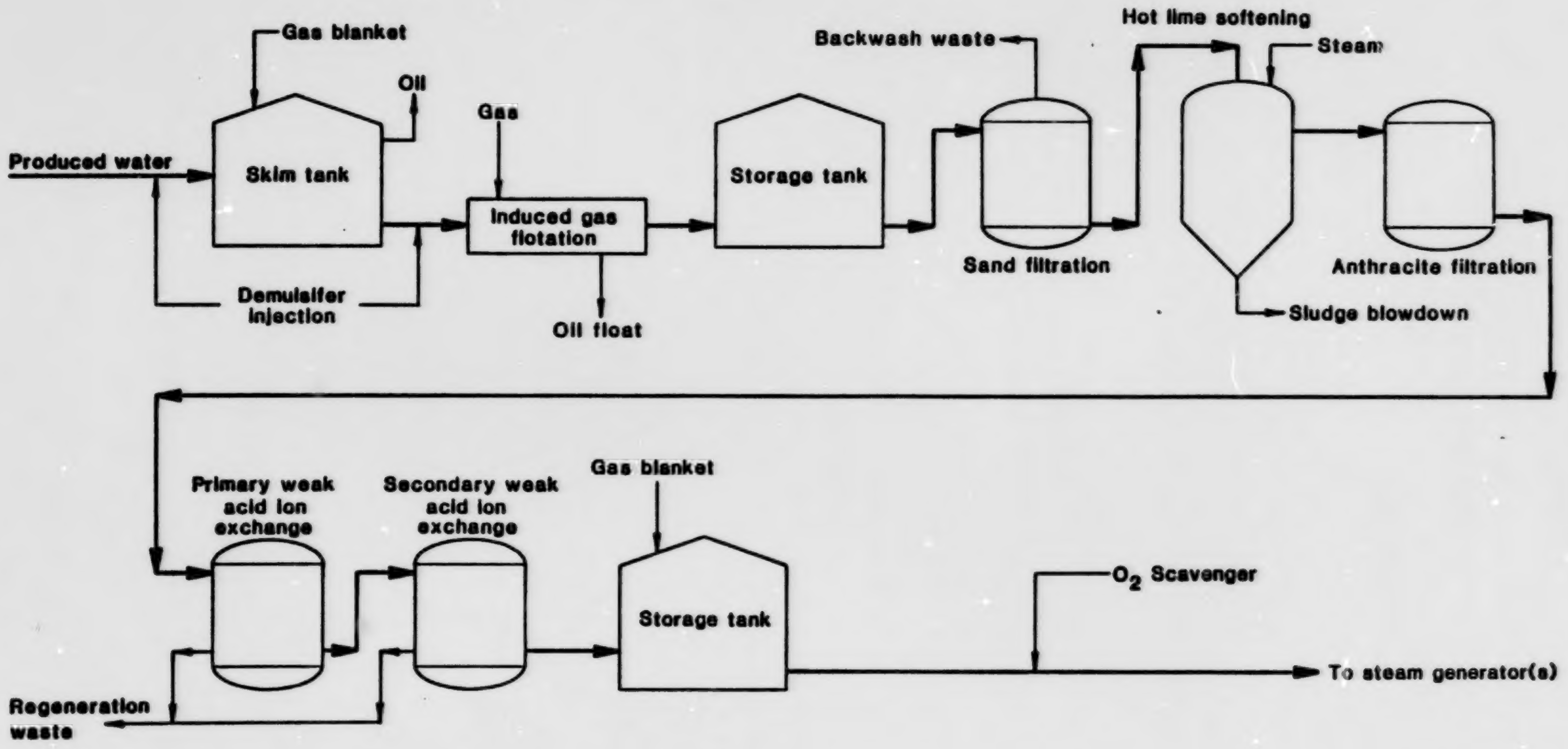

Produced water
Gas blanket
Oil
Skim tank
Demulsifer injection
Gas
Induced gas flotation
Oil float
Storage tank
Backwash waste
Sand filtration
Hot lime softening
Steam
Sludge blowdown
Anthracite filtration
Primary weak acid ion exchange
Secondary weak acid ion exchange
Regeneration waste
Gas blanket
Storage tank
O_2 Scavenger
To steam generator(s)

Figure 2-2
PROCESS SCHEMATIC FOR TREATMENT OF PRODUCED WATER TO ONCE-THROUGH STEAM GENERATOR FEEDWATER QUALITY

has been successfully used in several applications for the separation of heavy crude oils from produced water, in cases where the differences in specific gravity are relatively low. Gas (i.e., nitrogen or natural gas) is used in the flotation process instead of air due to the extreme corrosivity of the hot, saline produced water when oxygen is introduced.

The addition of chemical demulsifiers to the skim tank - IGF process is normally required to achieve effective oil removal. Many different types of chemical demulsifiers are available and their application is very site specific. Dosage rates can vary from a few mg/L up to 2000 mg/L in some instances of very "tight" oil-in-water emulsions which are difficult to break.

Effluent from the IGF unit typically contains between 10 and 25 mg/L of free oil. This can subsequently be reduced to less than 5 mg/L in a polishing filter. Both precoat (diatomaceous earth) and fixed bed (sand) filters have been successfully used in this application. While the former have been particularly successful in achieving low effluent oil concentrations, they are more difficult and costly to operate. Some problems with blinding of sand filter media have been encountered, particularly under upset conditions in which the IGF unit releases high effluent oil concentrations. This can be alleviated by the addition of gas scour equipment and/or chemical dispersants to the filters which aids the dispersion and release of trapped and agglomerated oil during backwash. The addition of an intermediate storage tank, with provision for oil removal between the IGF unit and filters can also provide an opportunity to catch high effluent oil concentrations escaping the IGF unit prior to blinding the filters. Despite these precautions, most operators find it necessary to occasionally change the sand filter media.

Following oil removal, hot lime softening and ion exchange are used to reduce silica and remove hardness. These processes coupled together as illustrated in Figure 2-1 have demonstrated an ability to produce an effluent low in silica with essentially zero hardness, when treating de-oiled produced water.

In the hot lime process, lime and magnesium oxide are added to the water to precipitate calcium, magnesium and silica. Soda ash may also be added to further reduce hardness and coagulant aids may be used to improve solid/liquid separation. The softening process is carried out in a pressure vessel between 100°C and 115°C (212 - 240°F). At this operating temperature, the softening reactions are considerably enhanced yielding effluent hardness levels of 5 - 20 mg/L as $CaCO_3$. Because the feedwater is sprayed into a steam atmosphere, dissolved gases are also stripped from the water. Trace amounts of oil can be removed by adsorption on the precipitates formed. However, oil in concentrations above 10 mg/L should be reduced upstream of the hot lime process, as higher concentrations may cause foaming or exert a dispersing influence causing floc carryover.

Hot process softening also provides good silica reduction. This is accomplished by the adsorption of the silica on the magnesium hydroxide precipitate. Good sludge contact enhances silica reduction. Hence, to ensure optimum contact, sludge is frequently recirculated back to the inlet of the vessel. Accumulated sludge must be periodically blown down from the softener and sent to disposal. While effluent silica concentrations as low as 2 - 5 mg/L are attainable with hot process softening, target levels of 20 - 40 mg/L are more typically used in produced water treatment applications, due to the less stringent feedwater quality requirements of once-through steam generators, as compared to high pressure utility boilers.

Anthracite filters are provided following the hot lime softener for removal of any floc or turbidity carryover from the unit. Sand media is not normally used due to the potential for silica pickup by the hot alkaline water.

Removal of the residual hardness remaining after hot lime softening can be accomplished by two-stage ion exchange. For waters with TDS concentrations of less than about 2500 mg/L, conventional sodium zeolite, salt-regenerated softeners can be used.

However, for waters containing in excess of 2500 mg/L of TDS, as is frequently the case with produced water, weak-acid carboxylic resins effect a more efficient removal of hardness with lower leakages.

A primary and secondary softener configuration is normally used to ensure that the effluent water contains essentially zero hardness. The secondary softener acts as a polisher removing the hardness leakage from the primary unit.

SUMMARY

Current steam injection practice in western Canada for oil recovery generally entails the use of conventional, once-through, 80 percent quality steam generators. These are characterized by three distinct features:

1. They are fuelled by oil or natural gas.
2. Feedwater is either softened freshwater or produced water which has undergone substantial pretreatment.
3. Atmospheric emissions of pollutants are generally uncontrolled.

Alternative steam generation technologies have been employed or proposed which offer one or more of the following advantages:

1. They burn low-grade solid fuels (e.g., coal and petroleum coke).

2. Feedwater pretreatment requirements are minimal.

3. Combustion gases are injected to the oil-bearing formation or the concentrations of air pollutants which they contain are substantially reduced.

In addition, some of these processes claim to exhibit higher energy conversion efficiencies while others are reported to improve oil recoveries as compared to conventional steam injection. The alternative steam generation processes which will be reviewed in Chapter 3 include the following:

1. Thermosludge Steam Generation
2. Fluidized Bed Combustion
3. Wet Oxidation
4. Vapor Therm
5. Downhole Steam Generation

REFERENCE

2-1 Personal communication with R. Burton, Conoco Inc.

CHAPTER 3
ALTERNATIVE STEAM GENERATION TECHNOLOGY REVIEW

INTRODUCTION

The purpose of this chapter is to review the status of alternative steam generation technologies (i.e., other than conventional, once-through, 80 percent quality generators) which have been demonstrated or proposed for use in oil recovery applications. The processes considered include the following:

1. Thermosludge Steam Generation
2. Fluidized Bed Combustion (FBC)
3. Wet Oxidation (WO)
4. Vapor Therm
5. Downhole Steam Generation (DSG)

Process descriptions are provided for each technology and the advantages offered by each, from an oil recovery perspective, are identified. Feedwater pretreatment requirements, chemical and utility requirements and energy conversion efficiency are discussed. Process equipment is reviewed, the demonstrated performance and stage of development of each process are identified and the environmental impacts associated with the implementation of each technology are addressed.

THERMOSLUDGE STEAM GENERATION

Background

The Thermosludge process is a combined water treatment and steam generation process. It was developed in the 1960's for oil recovery applications in the Kern County, California heavy oil fields (Reference 3-1). The process was designed to produce steam directly from produced water without the elaborate pretreatment requirements normally associated with conventional steam generators.

The process was initially marketed by Gas Processors, Inc. in 1964/65, with the first commercial unit going into operation in 1966 at Occidental Petroleum's Gabriel lease near McKittrick, California (Reference 3-1). Through a series of corporate aquisitions, the process was subsequently marketed by Ameron Process Systems Division from 1971 to 1978, by Lawrence-Allison and Associates Corporation from 1978 to 1981, and currently by KTI Gas Processors (Kinetics Technology International Corp.) of Santa Ana, California.

Process Description

The Thermosludge steam generator produces 100 percent quality steam from low-quality feedwater with high dissolved solids concentrations. The process uses an internal softening technique to precipitate and suspend scale-forming reaction products in the steam drum, thereby eliminating the need for external feedwater treatment. It also uses a secondary heat transfer medium (a eutectic salt mixture), rather than direct firing, to reduce the heat flux through the boiler tubes and thereby minimize scale formation on heat transfer surfaces.

The process is illustrated schematically in Figure 3-1.

Preheated feedwater is fed from a high-pressure feedwater pump into the Thermosludge unit. Depending on the relative amounts of calcium, magnesium, silica, and sulfate ions present in the feedwater, soda ash and/or magnesium chloride may be proportionately injected into the feedwater to effect the appropriate softening reactions within the steam generator

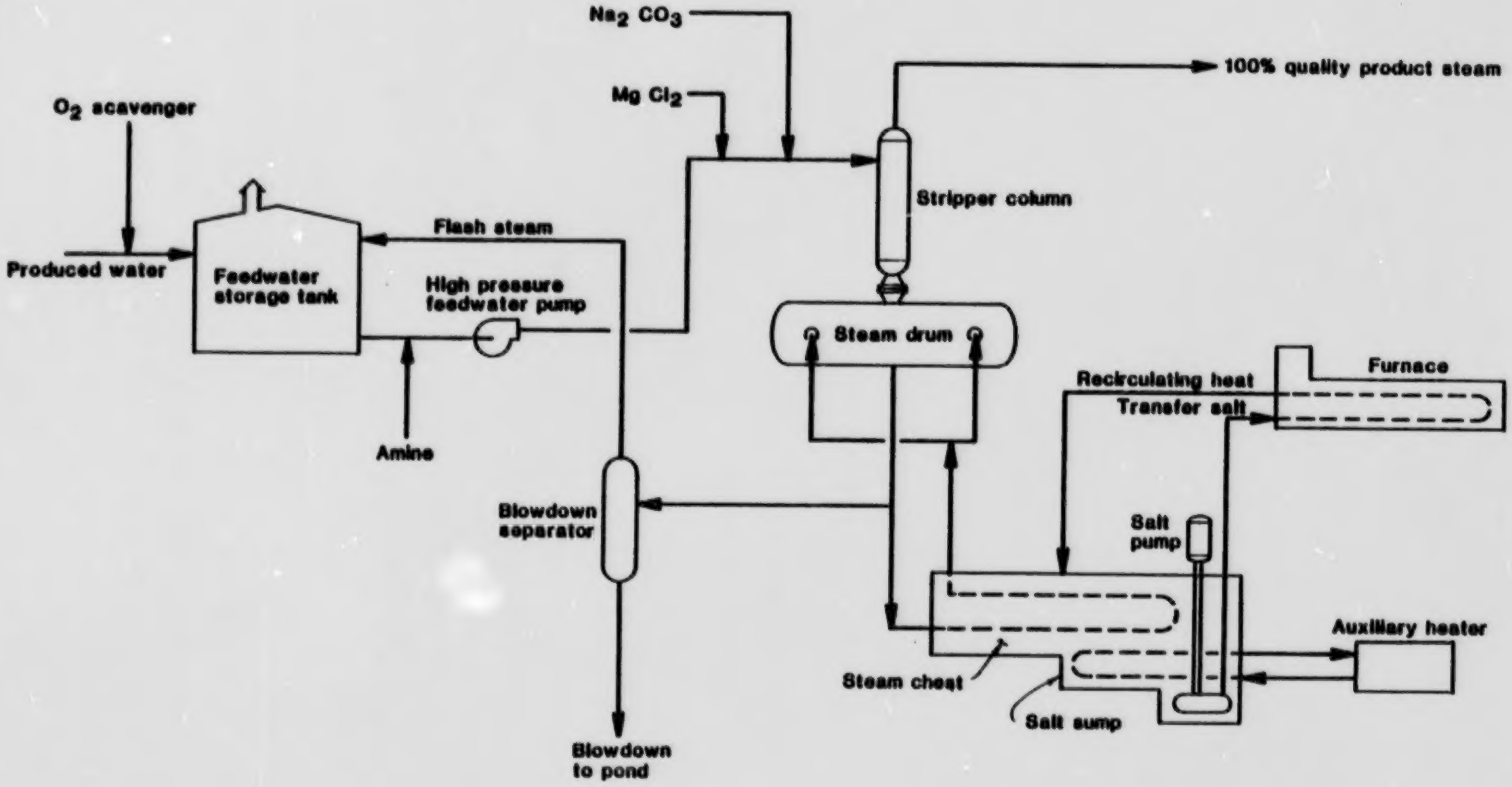

Na_2CO_3
$MgCl_2$
100% quality product steam
O_2 scavenger
Stripper column
Flash steam
Produced water
Feedwater storage tank
High pressure feedwater pump
Steam drum
Furnace
Recirculating heat
Transfer salt
Amine
Blowdown separator
Salt pump
Auxiliary heater
Steam chest
Salt sump
Blowdown to pond

Figure 3-1
THE THERMOSLUDGE STEAM GENERATION PROCESS

system. The feedwater enters the steam generator at the top of a vertical stripper column, passing downward, countercurrent to an upflow of steam from the steam drum, thereby stripping dissolved gases, some volatile organics and trace oils from the feedwater. Although claims have been made for the ability of the process to accept high oil concentrations, user experience indicates that pretreatment of the feedwater for gross oil removal is highly desirable to prevent foaming in the steam drum and oil deposition on heat exchange surfaces.

Depending upon feedwater chemistry, soda ash is added to keep the ratio of carbonate and bicarbonate ion concentration high in relation to the sulfate ion concentration. This promotes the precipitation of calcium carbonate sludge rather than calcium sulfate scale, the former being a much softer deposit at boiler temperature and more easily removed. Magnesium chloride is added to complex with silica to form a soft, nonadherent sludge, thereby further reducing the scaling tendency. A filming amine is normally added to control carbon dioxide corrosion within the system and sodium sulfite is also added as an oxygen scavenger. An antifoaming agent may also be required, depending upon the feedwater characteristics.

Feedwater chemistry is critical in determining the chemical requirements and thus, the operating cost of the Thermosludge process. In general, three conditions must be met:

1. Sufficient alkalinity must be present to form magnesium hydroxide ($Mg(OH)_2$) with all of the magnesium ion.

2. Enough carbonate must be present to form calcium carbonate ($CaCO_3$) with all of the calcium ions, and leave a residual or excess carbonate concentration sufficient to suppress calcium sulphate ($CaSO_4$) precipitation.

3. Enough magnesium must be present to complex with silica in a ratio of at least three magnesium hydroxide molecules to two silica molecules (i.e., $3\ Mg(OH)_2 : 2\ SiO_2$) (Reference 3-2).

If the natural alkalinity of the feedwater is insufficient to meet conditions 1 and 2, above, soda ash (Na_2CO_3) is added to provide the necessary alkalinity and carbonate ion. Likewise, magnesium chloride ($MgCl_2$) is added to provide sufficient magnesium ion to meet condition 3. With sufficient alkalinity present, the steam stripping of CO_2 from solution in the steam drum and in the stripper column causes the pH to rise to the 10 - 12 range. At this pH and with the temperature and retention time provided in the steam drum, the softening reactions are rapid and go essentially to completion (i.e., the formation of calcium carbonate, magnesium hydroxide, and magnesium silicate).

Slurry circulates by natural circulation (thermosyphon action) through a riser connection in each end of the steam drum into a group of horizontal tubes within the steam chest or heat exchanger. In the steam chest, heat is transferred from the recirculating eutectic salt mixture to the water tubes to produce steam. The salt is heated in an external, gas or crude-fired furnace. This method of indirect heating reportedly maintains unit heat flux rates and tube wall temperatures low enough to prevent scaling or coke formation on the inside of the boiler tubes.

Solid reaction products are present throughout the steam drum as a soft sludge, a portion of which is continuously removed as a blowdown from the system. The rate of blowdown required is a function of the dissolved solids concentration in the feedwater, but typically ranges between 10 to 20 percent of the feedwater rate. The blowdown is composed primarily of relatively inert calcium carbonate, magnesium hydroxide, and magnesium silicate. Free oil not removed ahead of the process is normally adsorbed or entrained on the sludge particles. The blowdown is flashed off at atmospheric pressure, with the resultant steam being used to preheat the feedwater. The remaining liquid/solid waste stream is normally discharged to a settling pond.

Product steam leaves the Thermosludge unit at the top of the stripper column, at 100 percent quality. In addition, it contains carbon dioxide and other gases stripped from the feedwater.

The boiler manufacturer quotes overall thermal efficiencies in the 75 - 80 percent range, which have been supported by users.

KTI Gas Processors are currently constructing a pilot plant to test a new process concept which they have named the Thermosoft process (Reference 3-3). It is, in fact, a water treatment process rather than a steam generation process, and incorporates Thermosludge technology with the well established hot lime softening process for water treatment. It is hoped the process can be applied to the treatment of produced waters to generate an effluent (feedwater) of suitable quality that it can be directly fed to a conventional once-through steam generator. The incentive for development of the Thermosoft process was the limited heat output which can be achieved from the Thermosludge steam generator as compared to conventional once-through generators.

The Thermosoft process is illustrated schematically in Figure 3-2.

In theory, produced water will be sprayed into the top of a pressurized stripping column. Soda ash will be fed just prior to the stripper at a concentration sufficient to precipitate essentially all of the calcium and magnesium

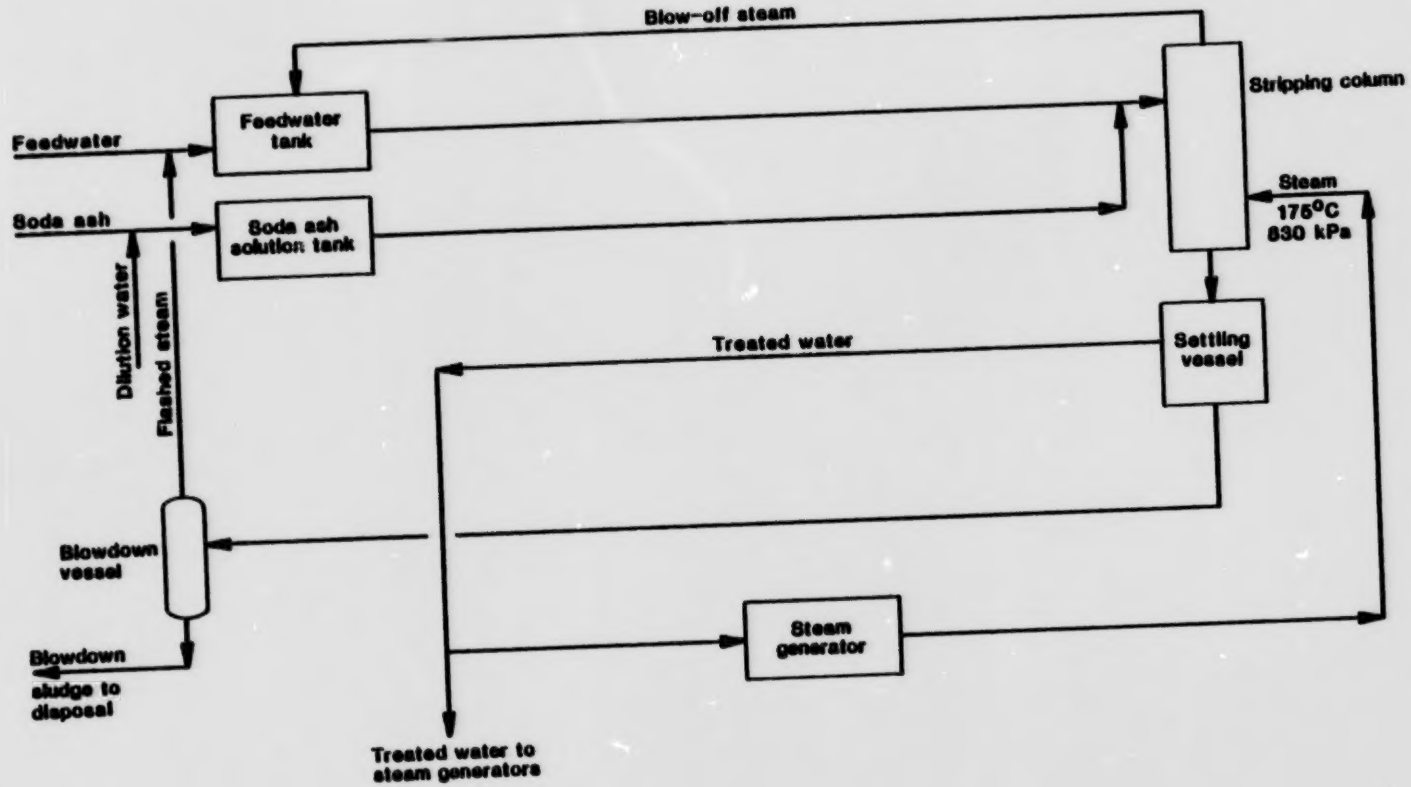

Blow-off steam
Stripping column
Feedwater
Feedwater tank
Soda ash
Soda ash solution tank
Steam
175°C
830 kPa
Dilution water
Flashed steam
Settling vessel
Treated water
Blowdown vessel
Blowdown sludge to disposal
Steam generator
Treated water to steam generators

Figure 3-2
THE THERMOSOFT WATER TREATMENT PROCESS

ions in solution. Saturated steam at approximately 175°C (350°F) and 830 kPa (120 psig) will be introduced at the bottom of the stripper. Steam will flow upward, countercurrent to the falling film of water, thereby stripping dissolved gases and volatile organics from the feedwater. As the feedwater temperature increases towards the bottom of the stripper, the rate of the calcium and magnesium precipitation reactions also increases. The resulting rise in temperature and pH in the feedwater decreases the solubility of calcium carbonate and magnesium hydroxide.

The softening reactions are predicted to reach equilibrium before the free falling water reaches the bottom of the stripper. The water/sludge mixture will then be directed to a settling vessel, where soft water will be decanted as feedwater for conventional once-through steam generators.

Several questions remain to be answered about the process such as the following:

1. What level of residual hardness will remain in the softened water and will this be low enough to be fed directly to conventional steam generators without polishing?

2. Will silica removal also be required for successful steam generator operation, and if so, can this be accomplished in the Thermosoft process?

3. What degree of oil removal will be required ahead of the process?

4. How will large quantities of softened feedwater be stored to prevent flashing?

5. Is simple settling sufficient to remove precipitated salts or will filtration be required? If so, what system is available to perform this hot high pressure filtration?

Initial operation of the pilot plant is currently planned for 1982.

Process Equipment

The principal Thermosludge process equipment is illustrated in Figure 3-1. The unit is comprised primarily of a high pressure feedwater pump, stripper, steam drum, steam chest, and furnace. Most of the process equipment is of conventional carbon steel, pressure vessel construction. The unit is relatively large and heavy compared to a conventional once-through steam generator of similar capacity.

The heat transfer salt is a sodium/potassium/nitrite/nitrate eutectic mixture. It has a melting point of approximately 135°C (275°F) and consequently requires the firing of an auxiliary heater on a cold startup. The system is designed so that the molten salt drains to the steam chest sump on shutdown.

The furnace is designed for firing on gas or crude oil. Apparently no significant efforts to date have been directed towards the development of a solid-fuel fired Thermosludge unit.

Thermosludge systems are currently available in design pressures up to 14 MPa (2000 psig) and nominal capacities of up to 7.3 MW (25 MM BTU/hr), although a 15 MW (50 MM BTU/hr) unit has been proposed.

Demonstrated Performance

The Thermosludge process has been considered a commercially demonstrated process for the generation of steam from produced water, since the mid 1960's. Several units have been used in EOR applications by operators in California such as Belridge Oil Co. (now owned by Shell), Union Oil Co., and Occidental Petroleum. In Canada, Texaco at Fort McMurray and Texasgulf at North Battleford have also operated units.

Nonetheless, the Thermosludge process has never gained the widespread commercial acceptance that the conventional once-through steam generator has in produced water reuse applications. In an effort to gain some insight into the long-term performance of the system, some users were contacted to discuss their operating history with Thermosludge units. In general, most users reported a satisfactory performance record indicating that the units had performed well with relatively little operator attention or maintenance. Most users were satisfied with the mechanical design of the system, although less so with the instrumentation provided on the units. The most common operating problem cited was that of water-side scaling. This appears to be caused primarily by chemical feed system failures or insufficient chemical addition. Some foaming and oil fouling problems were also identified, primarily on units which did not provide some pretreatment for oil removal.

It would appear that the reason conventional steam generators have been favoured over Thermosludge units is primarily an economic one rather than a technical one. Although water pretreatment costs are substantially reduced, the capital and operating costs of the Thermosludge system normally exceed those of conventional units in most cases. This is particularly true as the steam generation capacity increases. Thermosludge units operate at approximately a 10 - 15 percent lower thermal efficiency than conventional units resulting in proportionately increased fuel costs.

Environmental Implications

From an environmental perspective, the Thermosludge process is not significantly different from a conventional steam generator. However, from the standpoint of atmospheric emissions, since it burns slightly more fuel than a conventional steam generator, the total emissions per unit output of steam are somewhat higher.

The boiler blowdown stream is relatively innocuous, although it can be of significant magnitude and must ultimately be disposed of. It is normally high in both suspended and dissolved solids and typically requires solid/liquid separation, followed by deepwell injection of the decant.

FLUIDIZED BED COMBUSTION

Background

Considerable interest has been generated in fluidized bed combustion (FBC) in the past decade, as the process offers several advantages over conventional pulverized coal firing for energy conversion. Some of the principal advantages cited for FBC technology include the following:

1. The ability to burn a wide range of low-grade solid fuels in a single facility, including coal sizes up to 40 mm (1.5 in).

2. Lower combustion temperatures contributing to lower NO_x emissions than in a pulverized coal fired boiler.

3. SO_2 emissions can be controlled by the addition of limestone or dolomite to the boiler itself, thus eliminating the need for expensive flue gas scrubbing facilities, which are difficult to operate and typically produce a wet, voluminous, hard-to-handle sludge.

Most of the emphasis in the development of FBC technology has been directed towards the design of superheated steam utility boilers for electrical power generation applications. However, in recent years the potential for applying the process to develop a solid-fuel-fired, oilfield steam generator has been recognized.

There are several FBC technologies currently under development or available for commercial application. Struthers Thermo-Flood Corporation and Pyropower Corporation are both marketing FBC systems for oil recovery applications. While the process equipment design details vary somewhat between manufacturers, the process concepts are similar and are described below.

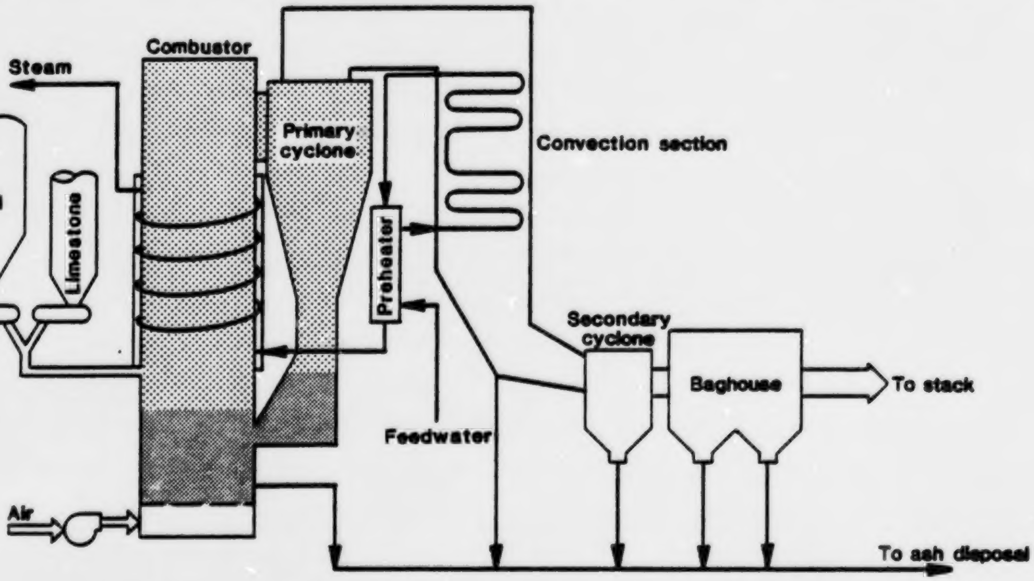
Process Description

In fluidized bed combustion, crushed (not pulverized) coal is burned in a bed of granular, nonvolatile material. Combustion air is passed up through a grid plate at sufficient velocity to fluidize the bed material, which may consist of sand, sorbent (limestone or dolomite) and coal ash. Fuel and sorbent are continuously fed to the bed by various techniques. These include feed through the air distributors at the bottom of the bed, pneumatic transport and addition through feed points located within the bed, and the feeding of materials over the surface of the bed using devices such as a spreader-stoker. The coal is ignited and mixes turbulently with the inert particles, maintaining a relatively stable temperature throughout the bed. The bed normally operates within a temperature range of 820° to 920°C (1500 - 1700°F).

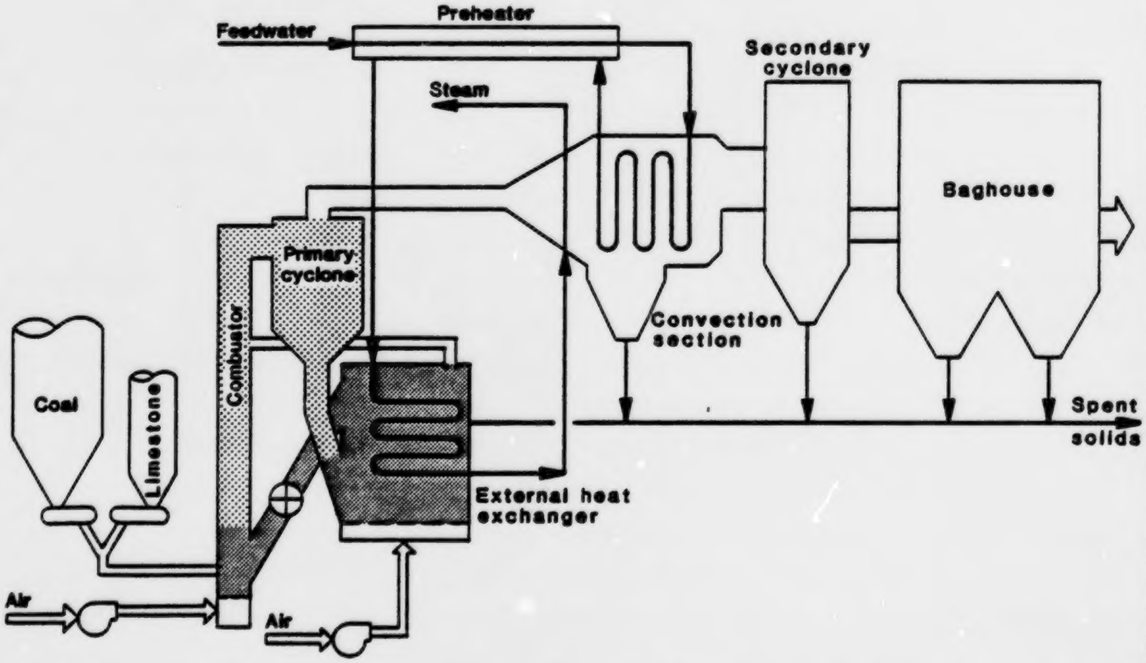
Heat transfer surfaces may be located within the bed, outside it, or in both locations. These may consist of boiler tubes placed within the bed or membrane-type waterwalls which enclose the combustion zone. Convective heat transfer surfaces may also be placed downstream of the combustion zone. The direct impact of the hot particles against the heat transfer surfaces submerged in the bed results in high rates of heat transfer.

Ash, fragments of the limestone/dolomite bed material, and unburned coal particles are carried from the fluidized bed by the combustion gases. At the lower combustion temperatures used in the fluidized bed, carbon utilization is usually lower than conventional pulverized coal-fired boilers. To obtain higher combustion efficiencies, and higher sorbent utilization rates, particulates entrained in the flue gas must be captured in collectors and recycled to the bed.

One of the significant differences between alternative FBC designs is the location of the heat transfer surfaces. In conventional FBC design, boiler tubes are frequently submerged within the fluidized bed combustion zone. Pyropower uses waterwalls which surround the combustion zone, as well as heat exchange surfaces in the flue gas stream, downstream of the particulate removal system. The Struthers system on the other hand, which is modelled after Battelle Columbus Laboratories' Multisolid FBC Process, removes the heat exchange surfaces from the combustion chamber and places them in an external heat exchanger. This is a mildly fluidized bed which reportedly overcomes many of the serious erosion and metallurgical problems which have plagued boiler tubes located within the fluidized bed combustion zone (Reference 3-4). Additional heat transfer surfaces are also placed in a downstream convection section. The two concepts are illustrated schematically in Figure 3-3.


Combustor
Steam
Primary cyclone
Convection section
Coal
Limestone
Preheater
Secondary cyclone
Baghouse
To stack
Feedwater
Air
To ash disposal

PYROPOWER CORPORATION FBC STEAM GENERATOR


Feedwater
Preheater
Secondary cyclone
Steam
Baghouse
Primary cyclone
Combustor
Convection section
Coal
Limestone
Spent solids
External heat exchanger
Air
Air

STRUTHERS / BATTELLE MULTISOLID FBC STEAM GENERATOR

Figure 3-3
FBC STEAM GENERATION PROCESSES

Another significant design variation between processes is the fluidizing velocity used. In conventional FBC systems, air is passed upwards through the bed at velocities typically in the range of 0.3 to 4.5 m/s (1 to 15 ft/s). A fluidizing velocity is normally selected that minimizes the loss of bed material by elutriation. In a circulating bed design such as that employed in the Pyropower and Struthers/Battelle FBC processes, high superficial velocities (4.5 - 9 m/s (15 - 30 ft/s)) are used in the combustor, which results in a significantly smaller cross sectional area than is the case with a conventional FBC design (Reference 3-4). The highly turbulent conditions in the combustor which result from the use of high fluidizing velocities also reduce the number of feed ports required to ensure uniform solids distribution throughout the bed. In the Struthers/Battelle process, low fluidizing velocities (0.5 - 0.6 m/s (1.5 - 2.0 ft/s)) are used in the external heat exchanger to minimize erosion of the horizontal boiler tubes (Reference 3-4).

In the combustion process, sulphur in the fuel reacts with oxygen in the combustion air to form SO_2. The higher the sulphur content of the fuel, the higher the SO_2 emissions. In the FBC process, limestone sorbent is added to capture the SO_2 released in combustion. Consequently, the SO_2 emissions are considerably lower than would be experienced with a conventional pulverized coal-fired (PCF) boiler operating with the same fuel type. PCF boilers require flue gas desulphurization facilities (i.e., scrubbers) to achieve comparable SO_2 removals.

The limestone ($CaCO_3$) sorbent fed to an FBC boiler calcines to lime (CaO) at the bed operating temperature. The lime reacts with oxygen from the combustion air, and SO_2 formed during combustion to form gypsum ($CaSO_4$), which is removed as a solid waste.

The Ca/S molar ratio (i.e., the ratio of sorbent to sulphur) is an important factor in determining the SO_2 emissions from an FBC boiler, although several other factors such as bed temperature, residence time, and sorbent properties also affect SO_2 removal. The Ca/S molar ratio required to achieve a specified SO_2 removal generally increases as the sulphur content of the fuel increases. For instance, whereas Ca/S ratios of 1.5 to 2.0 may be adequate to achieve 90% sulphur capture from a low sulphur coal (i.e., less than 1% S), ratios as high as 4.0 to 5.0 may be necessary to obtain similar removals on say a 5 to 6% sulphur petroleum coke. Factors that can affect the Ca/S ratio required to meet a specified SO_2 emission include: the ratio of organic to pyritic sulphur in the fuel, the size distribution of the limestone, and the pore structure of the limestone.

Higher limestone utilization, and thus lower Ca/S ratios, can reportedly be achieved by recycling the elutriated solids to the combustion chamber, as is the case in the circulating bed design utilized by Struthers and Pyropower. Hot solids leaving the combustion chamber are captured and recycled to the bed. This increases the exposure of the unreacted limestone to SO_2, thereby decreasing the amount of excess sorbent required to achieve the desired SO_2 removals. Likewise, the recycling of unburnt carbon elutriated from the bed improves fuel utilization.

The Struthers/Battelle process uses a dense bed media which does not leave the combustor. The role of this material is to increase the residence time of the fuel, ash, and sorbent in the combustor and to promote thorough mixing of these materials to further increase carbon and sorbent utilization rates (Reference 3-5).

The FBC process is capable of burning many low-grade fuels, including coal, petroleum coke, and asphaltenes. Coal can normally be burned as-mined (40 mm or smaller), thus eliminating the need for pulverization facilities. While reactive fuels, such as coal, can normally be fed over the bed, the more difficult-to-burn fuels, such as coke, must be fed under the bed to provide sufficient residence time for complete combustion (Reference 3-6).

With the recirculating bed design, fine grades of limestone can be used without the attendant concerns regarding high sorbent losses due to elutriation. In general, the finer the limestone particle size, the higher the utilization rate. This is attributed to the sulphation of a thin outer shell on the surface of the limestone particles which retards the diffusion of SO_2 into the centre, preventing complete utilization of the available calcium. By reducing particle size, the specific area of the particles is increased, thereby increasing the conversion to sulphate.

Struthers have coupled the once-through design of their conventional gas or crude-fired oilfield steam generator with the Battelle FBC concept. Their FBC steam generator is normally designed to produce about 80 percent quality steam and can operate with high dissolved solids in the feedwater, provided all hardness has been removed. Thus, it has the capability to reuse produced water as feedwater, provided it has been treated to the same specifications outlined in Chapter 2 for conventional once-through steam generators. This typically requires treatment for the removal of oil, suspended solids, silica, and hardness.

The thermal efficiency claimed for the FBC process is approximately 77 - 78 percent in terms of the total heat output as compared to the heat value of the fuel input. The overall efficiency of the process including energy inputs for pumps, blowers and miscellaneous equipment is estimated at approximately 75 percent.

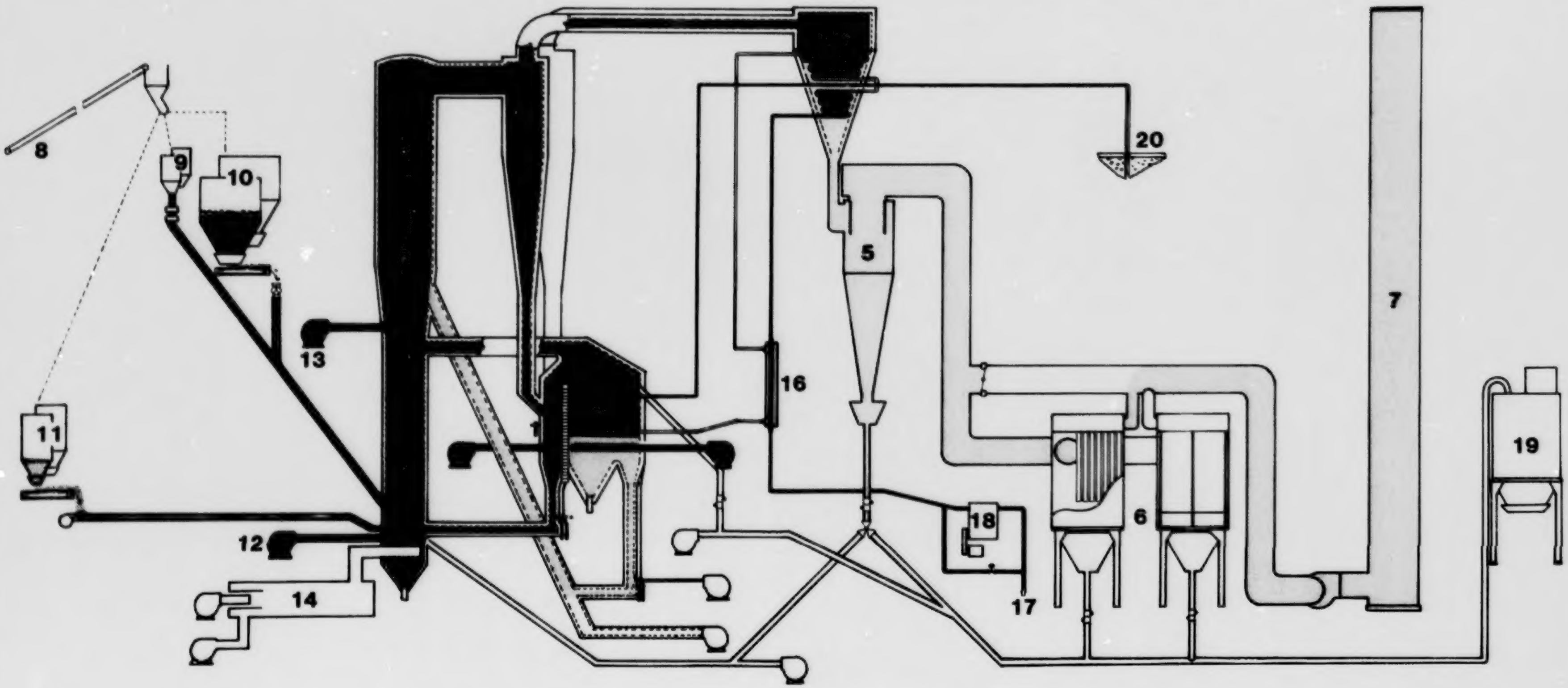
Process Equipment

The key process equipment comprising an FBC steam generator using the Struthers/Battelle design is illustrated in Figure 3-4. A large component of the system is the front end materials handling equipment for fuel and sorbent. Conveyors, classification equipment, storage bins, and feeders may comprise as much as 35 percent of the total cost of the facility (Reference 3-6).

The combustor is approximately 15 m (50 ft) high and increases in diameter with increasing capacity. The bed depth within the combustor is approximately 0.7 m (17 in) in the slumped condition and 1.2 m (48 in) in the expanded condition (Reference 3-6). The unit is designed to incorporate staged combustion by using a low primary air/stoichiometric air ratio, which maintains a highly reducing environment in the lower section of the combustor. Combustion is completed above the secondary air inlet. This, coupled with lower combustion temperatures as compared to pulverized coal firing, reportedly reduces the rate of NO_x formation.

Solids elutriated from the combustor are captured in the primary cyclone and fed by gravity to the external heat exchanger. Fines entrained in the flue gas, which escape capture in the primary cyclone, pass on to the convection section and are subsequently removed in either the secondary cyclone or the baghouse prior to flue gas discharge. A by-pass duct is normally provided around the baghouse, to isolate bag materials from moisture condensation during low temperature startup conditions.

The decoupled heat exchanger contains two chambers; one for storage and recycle of hot solids, the other for heat transfer and recycle of the cooled solids. Hot solids enter the heat exchanger at 820 - 920°C (1500 - 1700°F) and are cooled to



1 COMBUSTOR
2 PRIMARY CYCLONE
3 EXTERNAL HEAT EXCHANGER
4 CONVECTION SECTION
5 COLLECTOR CYCLONE
6 BAGHOUSE
7 STACK
8 BELT CONVEYOR
9 DENSE BED SAND
10 COAL / COKE BINS

11 LIMESTONE BINS
12 PRIMARY AIR BLOWER
13 SECONDARY AIR BLOWER
14 PREHEAT COMBUSTOR
15 HOT RECYCLE CHAMBER
16 FEEDWATER PREHEATER
17 FEEDWATER
18 FEEDWATER PUMP
19 ASH STORAGE BIN
20 80% STEAM PRODUCT TO WELL

Figure 3-4
STRUTHERS/BATTELLE FBC PROCESS SCHEMATIC
(Courtesy of Struthers Thermoflood Corp.)

approximately 600°C (1100°F) in the heat transfer chamber (Reference 3-4). The recycle rate of cooled solids is raised to control the combustor temperature. This external heat exchanger arrangement eliminates the need to slump portions of the combustor bed to respond to decreasing load, as is the case with conventional FBC designs. The hot solids recycle loop, which neither adds nor removes heat from the combustor permits the total solids recycle rate, and thus the solids residence time in the combustor, to be controlled independently of the load characteristics. This improves both limestone utilization and carbon burn-up (Reference 3-4).

Waste solids from the process, discharged from the cyclones and baghouse are pneumatically conveyed and stored for transport to a disposal site.

Feedwater to the process is preheated by heat exchange with the steam/water mixture exiting the convection section. The feed stream then passes through the convection section or economizer where heat is extracted from the flue gas leaving the primary cyclone. It is then passed back through the preheater and into the external heat exchanger where the steam quality is raised to approximately 70 percent. This stream then makes one final pass through the convection section to raise the product steam quality to approximately 80 percent.

The Struthers FBC pressue vessel piping materials are all carbon steel. Alloy materials (304 and 310) are used in such areas as air distributors, thermowells, and refractory supports. In addition, the primary cyclones contain a hastelloy metal gas outlet duct or center tube. While the amount of alloy materials is a small percentage of the total, they are utilized in areas where high temperature, erosion or friction (solids gravity feed areas) are a concern (Reference 3-20).

The general control philosophy used in the Struthers/Battelle process is as follows:

1. Water flow rate is controlled by a manual set point or by load-following to maintain a preset back pressure.
2. Fuel feed is controlled in direct ratio to the water flow rate.
3. Sorbent feed is controlled proportional to fuel feed rate.
4. Primary and secondary air flow rates are controlled in direct ratio to the fuel feed rate.
5. The cold solids recycle rate from the external heat exchanger is controlled by combustor temperature.

Compared to conventional oilfield steam generators, the FBC process entails a lot of large process equipment. The size of much of the equipment, particularly the fuel and sorbent preparation and feeding facilities, does not change significantly over a range of capacities from 15 - 75 MW (50 - 250 MM BTU/hr). Thus, while the process is particularly capital intensive for small facilities, economies of scale can be realized in large installations.

Demonstrated Performance

While fluidized bed processes have been commonly used within the chemical process industry for many years, FBC is still regarded as an emerging technology for steam raising and power generation in North America.

There are approximately two dozen FBC test facilities in the United States conducting pilot or experimental work on the development of the technology. The largest commercial unit operated in North America was a 30 MWe station located at Rivesville, West Virginia (now closed), although several conceptual designs have been prepared for large utility plants ranging in size from 150 to 1000 MWe.

The first Canadian commercial FBC heating plant is currently under construction at Canadian Forces Base Summerside, Prince Edward Island, and is scheduled for commissioning in late 1983. It will produce 20 tonnes/h (18 tons/h) of steam at 965 kPa (140 psi) using high-sulphur coal with up to 30 percent waste wood as fuel (Reference 3-19).

Struthers have installed the first commercial unit in an oil recovery application for Conoco in South Texas. The unit is designed to produce 14 MW (50 MM BTU/hr) of 80 percent quality steam using coal as fuel and an oil saturated limestone as sorbent (Reference 3-6). The unit went into operation in 1981 November, but few details regarding the operation are available to date.

Pyropower is currently constructing a 14 MW (50 MM BTU/hr) FBC unit near Bakersfield, California for Gulf Oil Co., with a planned startup date of 1983 January. The unit will produce 80 percent quality steam and will also be used in an oil recovery application (Reference 3-7).

Both Struthers and Pyropower operate pilot plants and have demonstrated on a small scale (1.4 MW or smaller) the ability of the FBC circulating bed process to successfully burn coal, coke, and other low grade solid fuels. Additional commercial scale experience (14 MW and larger) will be required to demonstrate the technical and economic feasibility of the process in oil recovery applications.

Environmental Impacts

FBC technology has demonstrated an ability to substantially reduce SO_2 and NO_x emissions from the combustion of low grade solid fuels, as compared to conventional pulverized coal-firing. The high dust loadings entrained in the flue gas stream from fluidized bed combustors dictate that a two-stage particulate collection system be used to comply with most emission standards. The first stage typically consists of mechanical dust collectors (cyclones), followed by a second stage baghouse or an electrostatic precipitator. Fabric filtration currently appears to be the more prudent choice, since the high resistivity associated with FBC particulates makes capture difficult in an electrostatic precipitator.

Fluidized bed boilers can generate substantial quantities of solid waste, particularly when burning high sulphur fuels. As fuel sulphur content increases, so does the Ca/S ratio required to achieve a specified reduction in SO_2 emissions. This has the effect of greatly increasing the consumption of fresh sorbent, as well as the quantities of solid waste produced.

In general, FBC residue is dry and relatively easy to handle. It is comprised of ash, spent and unutilized sorbent, as well as small quantities of unburnt fuel. Several recent studies have investigated the properties of the waste from both a disposal and reuse perspective. Most work to date indicates that FBC waste can be safely disposed of by landfill, although some concerns have been expressed regarding the thermal reactivity of the material when wetted. Several possible by-product uses of FBC waste are currently under investigation including agricultural use as a soil conditioner, masonry block manufacturing material, synthetic aggregate, road bed material, and other uses (Reference 3-8). While preliminary findings are promising, further development work is required in this area.

The FBC steam generator operates without any liquid blowdown. The total steam/water mixture is injected to the reservoir. Thus, the only liquid wastes associated with the process are the wastewater streams generated by the water treatment process. Possible water treatment wastes would include lime softener sludge, filter backwash, and ion exchange regeneration wastes.

WET OXIDATION

Background

Wet oxidation (WO), also referred to as Wetox^R and wet air oxidation (WAO), is a process in which combustible material is oxidized in water at elevated temperature and pressure. The technology was first patented as the Bayer Process in 1888 and has followed parallel paths of development in several countries since that time (Reference 3-9).

The Wetox^R process, the registered trade name applied to the process marketed by WetCom Engineering Ltd. with technical support provided by the Ontario Research Foundation, is the result of research performed on the hydrometallurgical extraction of metals and the oxidation of peat, wood, and spent sulphite liquor. It uses a horizontal, stirred, multi-compartmented, cascading reactor (Reference 3-9).

The Zimpro WAO process, developed by F.J. Zimmerman in the 1950's for the treatment of pulp and paper wastes and sewage sludge, uses a single-chamber, vertical, unstirred reactor. A similar process developed in the late 1960's by the Lockheed Aircraft Corporation and marketed by Astro Metallurgical Corporation, uses unstirred multistage reactors.

A unique concept which has slowly evolved in recent years is one proposed by Vertical Tube Reactor (VTR) Corporation. The VTR process utilizes a below-ground, vertical U-tube reactor, suspended from the top of a conventional cased well 1500 to 6500 feet deep. The process uses the hydrostatic head exerted by the vertical column of water to achieve the required pressure for the wet oxidation process to proceed, thus eliminating the need for costly high pressure air compression and feedwater pumping facilities.

The differences between the specific reactor designs are illustrated in Figure 3-5. To date, the WO process has been used principally in waste treatment applications, and several facilities are installed worldwide for the treatment of organic and hazardous wastes. The application of the process to the generation of steam for oil recovery has been pursued primarily by Zimpro-AEC Ltd., a joint venture project between Zimpro Inc. and Alberta Energy Company Ltd. Thus, this discussion is limited to the Zimpro WAO process.

Process Description

Wet oxidation is a flameless combustion process that proceeds at temperatures typically in the 150 - 370°C (300 - 700°F) range, and pressures of 2000 - 20 000 kPa (300 - 3000 psi) (Reference 3-10). The reaction chemistry is complex, consisting of a family of related hydrolysis and oxidation reactions. In the overall process, however, combustible organic material is converted to carbon dioxide (CO_2) and water, sulphur in the fuel is converted to sulphates ($SO_4^=$), nitrogen in the fuel is converted to ammonia (NH_3), and metals are converted to metal oxides or hydroxides (Reference 3-11).

One of the major advantages claimed for the process is its ability to use produced water directly as feedwater, without pretreatment. In fact, residual oil remaining in the feed-

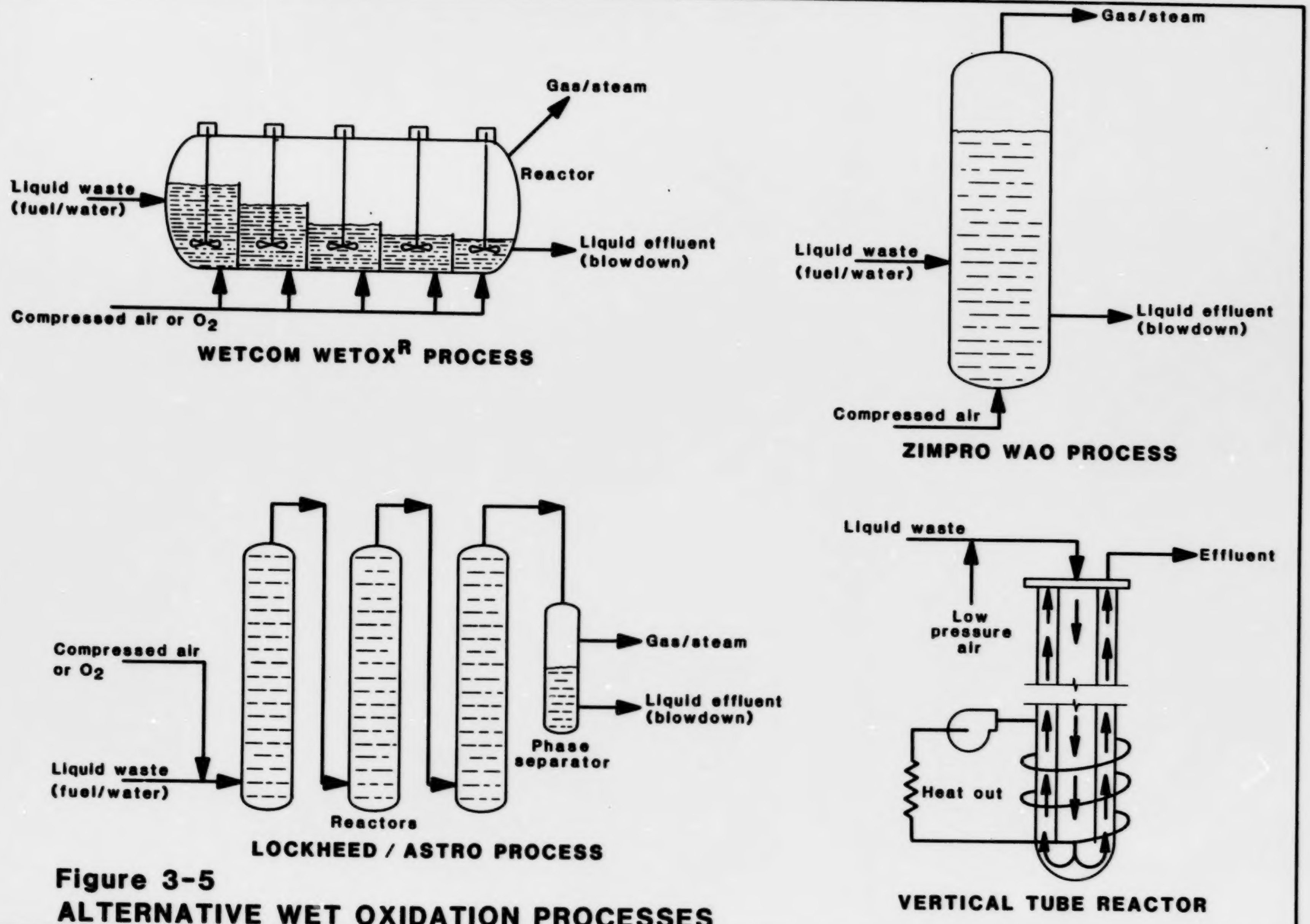

Gas/steam
Reactor
Liquid waste
(fuel/water)
Liquid effluent
(blowdown)
Compressed air or O2
WETCOM WETOX^R PROCESS
Gas/steam
Liquid waste
(fuel/water)
Liquid effluent
(blowdown)
Compressed air
ZIMPRO WAO PROCESS
Compressed air
or O2
Liquid waste
(fuel/water)
Reactors
Gas/steam
Liquid effluent
(blowdown)
Phase
separator
LOCKHEED / ASTRO PROCESS
Liquid waste
Low
pressure
air
Effluent
Heat out
VERTICAL TUBE REACTOR

Figure 3-5
ALTERNATIVE WET OXIDATION PROCESSES

water following oil/water separation would constitute a portion of the fuel to the process and would be oxidized in the reactor. Consequently, the need for breaking difficult oil-in-water emulsions is eliminated.

Dissolved solids in the feedwater can be concentrated to high levels in the reactor by virtue of the high temperatures and pressures which in turn contribute to high solubilities of many species. In addition, the production of CO_2, sulphuric acid, and hydrochloric acid within the reactor drives the pH of the system down as low as 1.0, thus enhancing the solubility of many minerals (Reference 3-11). Species whose solubility limits are exceeded precipitate and are removed from the system in a blowdown stream. The high concentrations of calcium, magnesium, silica and other ions typical of most produced waters suggests there is a significant potential for scale formation in the blowdown system (i.e., flash tank, piping, and valves). As the blowdown stream is flashed, instantaneous supersaturation of most dissolved salts will occur giving rise to potential scaling conditions.

Fuel to the WAO process may be any oxidizable organic material. Traditionally, WAO has been used in waste treatment applications, and organic materials such as sewage sludge and pulping liquor have comprised the "fuel" to the process. In oil recovery applications, coal, petroleum coke, and bitumen are being considered as potential fuels. Zimpro-AEC claims that slurries of these fuels will in fact be easier to handle and oxidize than the traditional waste materials used to date (Reference 3-10).

The process is illustrated schematically in Figure 3-6, as it might be used in oil recovery applications. The fuel is slurried with the feedwater in approximately a 50 percent mixture. Additional feedwater is added and controlled by the liquid level within the reactor. Oxygen to support the

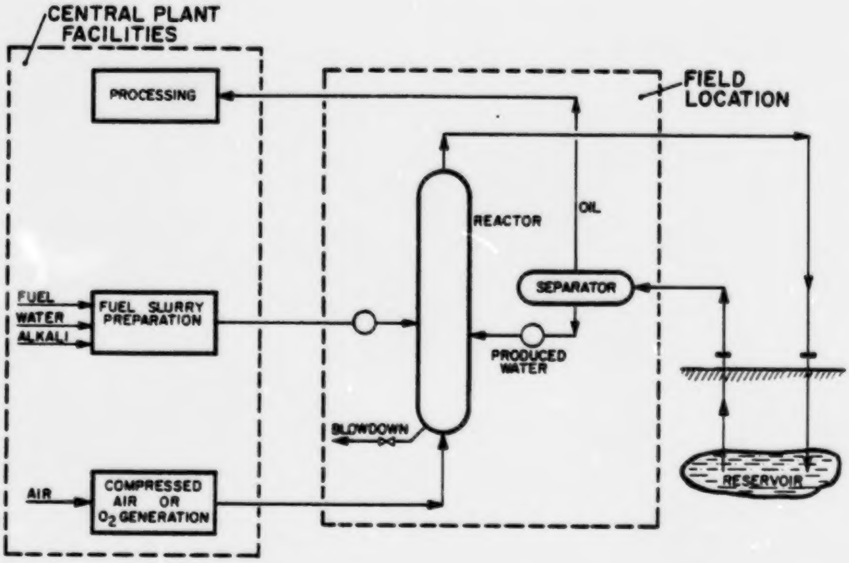

CENTRAL PLANT FACILITIES
PROCESSING
FIELD LOCATION
REACTOR
OIL
SEPARATOR
FUEL
WATER
ALKALI
FUEL SLURRY PREPARATION
PRODUCED WATER
BLOWDOWN
RESERVOIR
AIR
COMPRESSED AIR OR O_2 GENERATION

Figure 3-6
WAO PROCESS IN EOR APPLICATION
(Reference 3-10)

reaction process may be supplied either as compressed air or from an oxygen plant. The off-gas from a WAO/air unit will be primarily a mixture of steam, CO_2, and N_2, whereas a WAO/O_2 unit will produce principally a steam-CO_2 mixture. The entire off-gas stream is then injected to the oil-bearing formation to take advantage of the additional thermal energy and gas drive/ solubility associated with the products of combustion. In an alternative configuration, the WAO/O_2 process can be used as a CO_2 generator for EOR. In this application, steam in the off-gas is condensed and the "waste heat" is used to drive a turbo generator for cogeneration of electricity (Reference 3-12). The non-condensible gas stream, rich in CO_2, can then be used as a high pressure source of CO_2 for miscible flood projects.

In an oil recovery application, the WAO reactor would typically operate at approximately 315°C (600°F) and 14 MPa (2000 psi). The process uses less than 1 percent excess oxygen, and the fuel/ water ratio is controlled to provide approximately 80 - 95 percent evaporation of the feedwater by the heat of reaction. The dissolved and suspended solids concentrations in the reactor are controlled by a blowdown, which typically averages between 10 and 15 percent of the feedwater rate (Reference 3-11).

The energy conversion efficiency of the WAO process is approximately 88 - 92 percent in terms of the total heat output as compared to the heat value of the fuel input. The overall efficiency of the process, including energy inputs for air compression and/or O_2 generation, feedwater pumping, and miscellaneous requirements is estimated at approximately 71 percent for the WAO/air system and 74 percent for the WAO/O_2 process.

In summary, the principal advantages claimed for the WAO process in EOR applications are as follows:

1. There are no gaseous pollutant emissions.

2. Low-grade, high-sulphur fuels can be used.

3. Produced water can be used as feedwater to the process without pretreatment.

4. The steam/gas mixture injected to the reservoir may increase oil production over what can be achieved with steam alone, on an equivalent heat input basis.

Process Equipment

The principal process equipment items comprising a WAO boiler package are illustrated in Figure 3-7. The reactor is the heart of the process and represents probably the greatest single capital cost item. As a minimum this pressure vessel must be constructed with an inner cladding of titanium to withstand the very corrosive conditions resulting from the low pH, high oxygen, high dissolved solids, and high temperature environment. The use of other high alloy steels such as Hastelloy C have also been employed. The use of a single stage, unstirred reactor simplifies the construction and reduces the maintenance problems associated with this vessel as compared to alternative designs. Alternative designs have used mechanical agitation to increase the rate of reaction, and thus reduce residence time in the reactor as illustrated in Figure 3-8. However, Zimpro claims that there is no significant difference between reactors with mechanical agitation and their bubble column reactor (Reference 3-21).

The other major components of the WAO boiler package from a capital cost standpoint, are the high pressure feedwater and slurry pumps. These must operate in corrosive, abrasive service necessitating particular attention to their design.

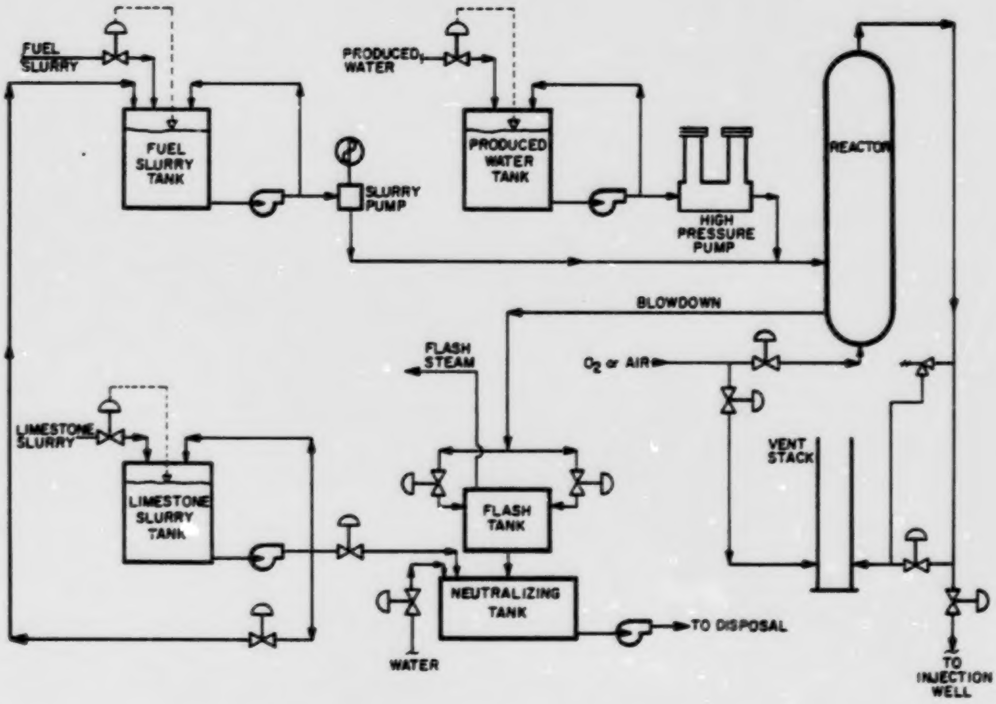

FUEL SLURRY
FUEL SLURRY TANK
SLURRY PUMP
PRODUCED WATER
PRODUCED WATER TANK
HIGH PRESSURE PUMP
REACTOR
BLOWDOWN
FLASH STEAM
O_2 or AIR
LIMESTONE SLURRY
LIMESTONE SLURRY TANK
VENT STACK
FLASH TANK
NEUTRALIZING TANK
TO DISPOSAL
WATER
TO INJECTION WELL

Figure 3-7
WAO PROCESS SCHEMATIC
(Reference 3-10)

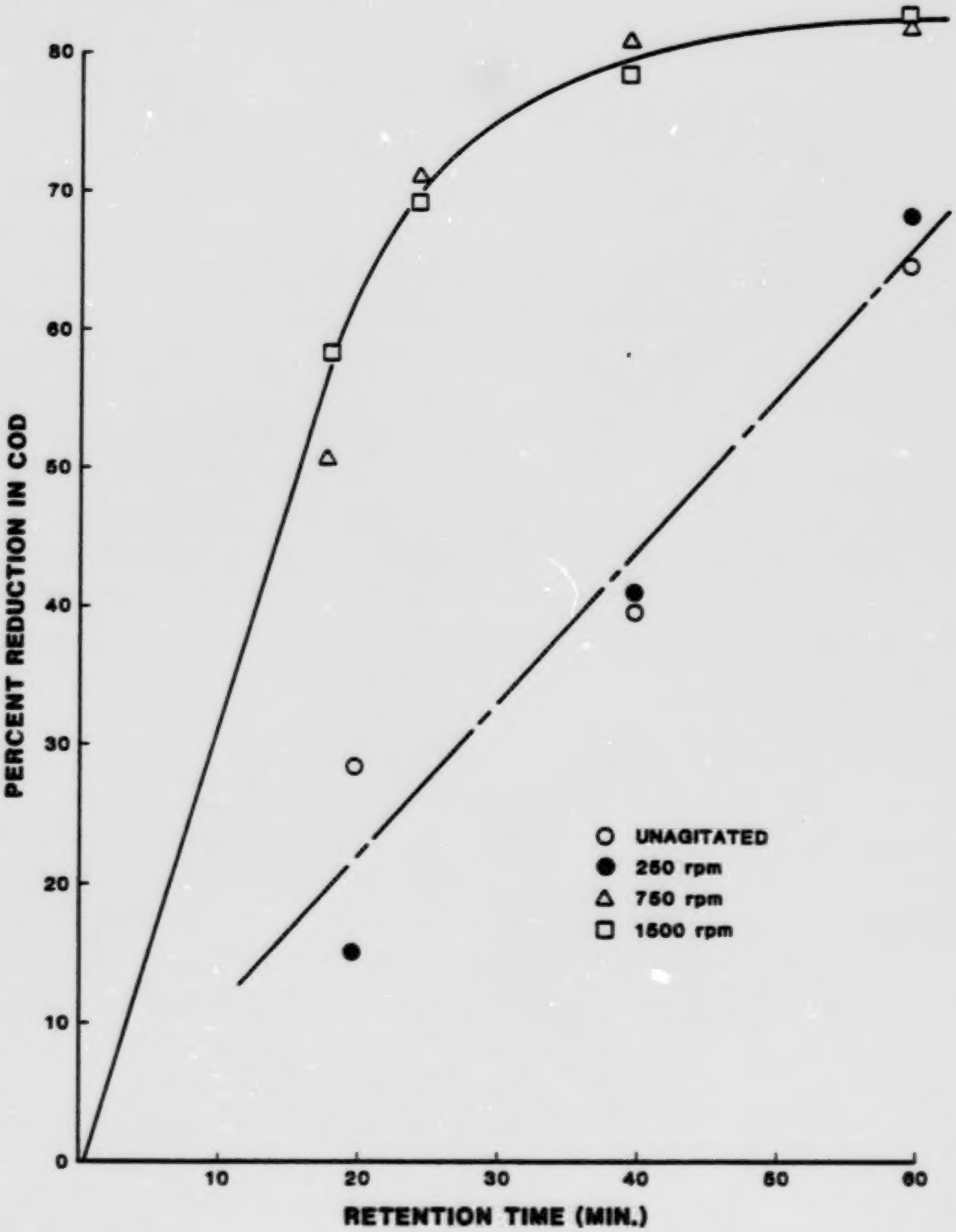


Figure 3-8
THE EFFECT OF AGITATION
IN WET OXIDATION
(Reference 3-9)

Not illustrated in Figure 3-7 are the fuel handling and storage facilities, air compression or oxygen supply equipment, and waste handling facilities, each of which represents a significant proportion of the total capital cost.

A WAO facility equipped for solid-fuel firing would require facilities for fuel unloading, long-term storage, conveyance, size reduction and classification, short-term storage, feeding, and metering.

As the reactor for an oil recovery application would typically operate at pressures in the region of 14 MPa (2000 psi), air compression equipment or an oxygen generation and compression plant constitutes a very sizeable proportion of the cost of the facilities.

The blowdown from the reactor is very acidic and is normally neutralized with limestone. This produces a sludge which would either be discharged to a pond or be dewatered for landfill. Due to the high dissolved solids concentration in the liquid phase of the blowdown, disposal of this waste stream would likely require either injection to disposal wells or costly treatment for dissolved solids concentration (e.g., evaporation and/or drying). In recent research and development work, Zimpro has found that it may be possible to recycle the waste brine to the reactor which would eliminate the liquid effluent stream, leaving only the waste solids requiring disposal (Reference 3-21).

Materials selection is critical to the success of the WAO process. Hot, brackish, and potentially sour produced water is very corrosive when exposed to oxygen. Thus, if an "open" system is to be used (i.e., exposed to atmosphere), all feedwater equipment must be lined or constructed of alloy materials. Likewise, the presence of CO_2 and residual O_2 in the wet product steam creates an aggressive environment downstream of the reactor. For corrosion protection in the steam distribution piping, three alternatives may be employed:

1. the use of alloy materials
2. the use of corrosion inhibiting chemicals
3. superheating the steam (Reference 3-10).

Superheating may be the preferred alternative, as it is relatively easy to do and the additional heat can be recovered in the reservoir. Carpenter 20 Cb3 is the material recommended for use in this type of corrosive service and the estimated cost of a steam distribution network is approximately four times the cost of a conventional carbon steel system (Reference 3-22). Thus it is apparent that the use of alloy materials can require a substantial capital investment. Similarly the use of corrosion inhibiting chemicals can represent a significant operating cost without a significant return, as compared to superheating.

It may be possible to use these techniques individually or in combination to relieve the corrosion problems anticipated with steam distribution piping coupled to the WAO process.

Zimpro-AEC has designed the process for control by a digital mini computer with data collection and storage capability. This will permit several remotely located boilers to be centrally monitored and controlled.

The mechanical equipment for a 14 MW (50 MM BTU/hr) unit can be assembled on two skids, each approximately 3 m X 10 m (10 ft X 35 ft), excluding the air compression or oxygen supply equipment, reactor, and tanks (Reference 3-11).

Demonstrated Performance

The wet oxidation process has been commercially demonstrated in numerous waste treatment applications. There are reportedly over 200 installations worldwide using the process for treatment of wastewater sludges, toxic organic, and hazardous liquid wastes (Reference 3-10). Several of these processes are equipped for by-product energy recovery.

Zimpro-AEC Ltd. have operated a 0.073 MW (0.25 MM BTU/hr) pilot WAO reactor in Rothschild, Wisconsin using bitumen, coal, syncrude coke, and wood as fuels. They have received the first request for a commercial unit to be used in an EOR application. It will be a 14.7 MW (50 MM BTU/hr) design for an Alberta in-situ, heavy oil recovery project. The project has been delayed, and as a result the construction, delivery, and startup schedule for the unit is still undetermined (Reference 3-11).

Zimpro-AEC have developed designs for the WAO units in sizes of 7, 14, 29, and 73 MW (25, 50, 100, and 250 MM BTU/hr).

The effects of injecting steam/gas and specifically steam/CO_2 mixtures on the reservoir and on oil recoveries have been of interest to several investigators. Many have hypothesized that steam/gas mixtures will enhance oil recoveries over those attainable by the use of steam alone. Zimpro-AEC commissioned a simulation study by Intercomp Ltd. to evaluate the benefits of injecting steam/CO_2 and steam/CO_2/N_2 mixtures compared to the injection of 80 percent quality steam alone. The results of the model are discussed in Appendix A.

Environmental Impacts

The WAO process offers a significant advantage over alternative steam generation processes from an environmental perspective, in that it reportedly emits no gaseous pollutants. All gases produced are injected downhole with the product steam. With some processes, which likewise inject combustion products, the concern has been expressed that SO_2 and NO_x may ultimately be vented from producing wells. However, in WAO, sulphur compounds in the fuel are converted to sulphates, while nitrogen is converted to ammonia, thus eliminating the concern regarding SO_2 and NO_x.

Since the process is capable of reusing a high percentage of produced water directly, without pretreatment, the associated water treatment wastes such as sludges and ion exchange regeneration wastes are eliminated. However, in their place, the process generates a blowdown stream which may represent as much as 20 percent of the throughput rate.

The blowdown from the WAO process will consist of ash from the fuel being utilized, high dissolved solids concentrations, and a significant concentration of precipitated species whose solubility limits have been exceeded. Once the blowdown has been flashed and neutralized with limestone, the solids can be separated and dewatered by conventional means (e.g., thickening, filtration, centrifugation). The characteristics of the remaining liquids and solids will largely determine how they are to be handled. Provided the solid waste is not determined to be hazardous, the sludge can likely be ponded or landfilled. The liquid stream, however, will be very high in dissolved solids and may contain residual, unoxidized organics which may require further treatment prior to discharge or necessitate disposal by deepwell injection. Further work is required to characterize the nature of the wastes produced by this process and to investigate effective methods of handling and disposing of this material. As indicated previously, Zimpro has recently found that it may be possible to recycle the waste brine to the reactor, thus eliminating the liquid effluent stream (Reference 3-21).

VAPOR THERM

Background

The Vapor Therm steam generation process has been developed by Carmel Energy Inc., Houston for use in EOR applications. The process was reportedly developed originally for sulphur recovery in the late 1960's (Reference 3-13). Carmel first adapted the unit for field testing in an oil recovery application in 1972, and has subsequently used the process in pilot and commercial projects. The process basically quenches combustion gases with a water spray, resulting in the formation of a steam/flue gas mixture for injection to the oil reservoir.

Process Description

The Vapor Therm process is illustrated schematically in Figure 3-9. Crude oil, diesel, or a blend of these fuels is burned in a combustion chamber. The hot combustion gases (1900 - 2200°C (3500 - 4000°F)) enter a quench chamber, where water sprays cool the gas to about 315 - 400°C (600 - 750°F). The water-to-gas ratio can be controlled such that saturated or superheated steam is produced, as desired. With saturated steam, the overall product stream typically consists of about 70 percent steam, 20 percent nitrogen, 10 percent carbon dioxide, and 0.5 percent oxygen (Reference 3-13).

A standing leg of water is maintained in the quench chamber containing high concentrations of soluble salts, as well as precipitates of compounds whose solubility limits have been exceeded. An intermittent blowdown from the quench chamber is used to control the concentrations of dissolved and suspended solids in this water leg. Typical blowdown rates reportedly average about 5 percent of the feedwater rate.

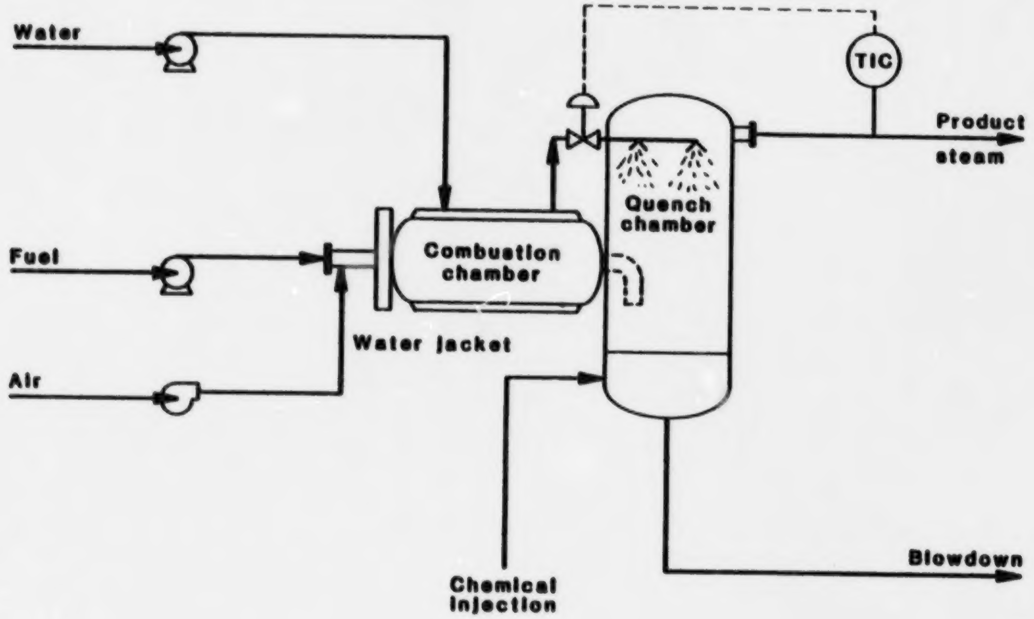

Water
Fuel
Air
Water jacket
Combustion chamber
Quench chamber
TIC
Product steam
Chemical injection
Blowdown

Figure 3-9
VAPOR THERM PROCESS SCHEMATIC

To date, only softened fresh water has been used as feedwater to the process. However, in reviewing the operation of the system, there is reason to expect that it would operate satisfactorily on a softened produced water supply. Softening is considered essential, as scale formation within the unit has been experienced during periods of poor softener performance (Reference 3-13).

Feedwater to the process is preheated in a water jacket which surrounds the combustion chamber and serves to cool the walls. The flow rate to the water sprays is controlled by the temperature of the outlet steam.

Chemicals added to the quench chamber include caustic, oxygen scavenger, and ammonia. Sulphur dioxide and carbon dioxide produced in the combustion process are scrubbed from the flue gas to some extent in the quench section. This lowers the pH of the liquid in the quench chamber giving rise to potential corrosion problems. Caustic is added to raise the pH for corrosion control.

The process operates at approximately 0.5 mole percent excess air. Thus residual oxygen in the quench chamber may also cause corrosion concerns. This is handled by the addition of oxygen scavenger.

Ammonia is apparently added primarily for electrochemistry control in the reservoir to prevent clay swelling problems.

The Vapor Therm unit has been built to operate at pressures between 2 and 10 MPa (300 and 1500 psi). Combustion air for the process must necessarily be supplied at the operating pressure. This necessitates a relatively high investment for air compression equipment, as well as a significant operating cost. Although the thermal efficiency of the unit is high, in that all of the flue gas heat energy is utilized, the high air compression requirements reduce the overall efficiency of the process to an estimated value of approximately 75 percent.

Carmel has also developed their Vapor Therm II process in which a Vapor Therm unit is coupled to a conventional 80 percent quality steam generator. This enables the inert gas content (carbon dioxide plus nitrogen) of the product stream delivered to the well to be varied from 2 to 35 percent (Reference 3-14). Although no corrosion problems in the steam distribution piping were identified during a site visit to a field facility using this process, a potential problem would appear to exist with the Vapor Therm II process. Carbon dioxide and oxygen in a wet steam environment is normally considered a very aggressive mixture with respect to corrosion of carbon steel.

While recognizing that the Vapor Therm process may not be directly competitive with conventional 80 percent quality steam generators when comparing only cost per unit heat output, Carmel claims that the injection of a flue gas/steam mixture improves oil recovery over steam alone, while eliminating atmospheric emissions (see Appendix A). Carmel prefers to compare the Vapor Therm process to downhole steam generation (DSG), as the process concepts are more closely related. They feel the Vapor Therm process offers several advantages over DSG, including the following:

1. Vapor Therm is well adapted to both steam stimulation (huff and puff) and steam drive (steamflood) applications. DSG is not well suited to a cyclic steam stimulation operation, because of the necessity to pull the generator from the bottom of the well to move from a steam injection to a production mode.

2. Vapor Therm can be applied to narrow bore well casing and tubing, whereas DSG normally requires a larger inside diameter to enable the generator to be run downhole.

3. The output from a Vapor Therm unit can be split between several injection wells, whereas one DSG unit can steam only one well at a time.

4. The advantages of a surface-located steam generation facility as compared to DSG include ease of chemical addition (e.g., polymers, foams, etc.), operation, maintenance, and process control (Reference 3-14).

Carmel claims the only disadvantage of Vapor Therm, compared to DSG is the heat loss between the generator output and the sand face. They feel this effect is small compared to the overall steam generation costs, and can be largely overcome by the use of an insulated tubing string (Reference 3-14).

Process Equipment

Vapor Therm equipment is all carbon steel construction and is manufactured by C. E. Natco under a licensing agreement with Carmel. Units constructed to date have had heat outputs up to 3.5 MW (12 MM BTU/hr) at pressures of up to 10 MPa (1500 psi) (Reference 3-13).

Currently, the process is not highly instrumented or automated. Field personnel indicated that combustion products are analyzed manually on an hourly basis, and the fuel/air mixture is adjusted accordingly. With the current level of instrumentation and automation, the process requires full-time, around the clock operator attention.

The process has only been designed to burn liquid fuels. It is not adaptable to solid-fuel firing as there is no easy means to separate the ash from the combustion gases. Conversion to gas firing would necessitate the addition of gas compression equipment in place of fuel pumps.

Demonstrated Performance

The Vapor Therm process was first tested in 1972 in the Blue Ridge oil field in Texas. It was a single well, single cycle test that demonstrated the process was uneconomic at the current oil price of approximately \$21.00 U.S./m³ (\$3.50 U.S./bbl) (Reference 3-14).

Following some equipment and process design modifications, the U.S. Department of Energy funded a four-well test in the Carlyle field near Iola, Kansas in 1976/77. Four injection cycles were run on this field and oil/steam ratios of 1.63 m³ oil/m³ steam were reportedly observed (Reference 3-14).

In 1978 the U.S. Department of Energy participated in a cost-share program with Carmel in Vernon County, Missouri. The initial three-well test in this field has subsequently been expanded by Carmel to a 120-well commercial project. In a comparison test with steam alone, conducted in this field, Carmel reports that the Vapor Therm process exhibited approximately a 50 percent increase in oil production with a 30 percent increase in operating cost, on the first injection/production cycle (Reference 3-13).

In would appear that the steam generation capabilities of the Vapor Therm process have been successfully demonstrated to date. Some further development of the process would appear to be appropriate, particularly with regard to the level of sophistication of the process instrumentation and controls. The demonstration of the process' capability to use softened produced water as feedwater would also be of considerable interest. To document the benefits claimed for steam-flue gas mixtures, as compared to steam alone, with respect to improved oil recoveries, considerably more work is required. Long-term testing of the two systems in parallel, under more tightly controlled conditions, is necessary to demonstrate the relative economics of Vapor Therm as compared to conventional steaming techniques.

Environmental Implications

The Vapor Therm process eliminates the discharge to the environment of atmospheric pollutants traditionally associated with the combustion of crude oil. Some of the pollutants (e.g., SO_2) are partially scrubbed from the flue gas in the quench chamber, while all residual gases are injected to the oil-bearing formation. Some recent results of DSG tests have indicated that a further reduction in SO_2 and NO_x occurs in the reservoir, thus reducing the likelihood of these residual pollutants being produced with the oil.

With the exception of the boiler blowdown stream, the only liquid wastes produced by the process are those associated with the water treatment facilities, which would be similar to those produced by conventional steam generation.

DOWNHOLE STEAM GENERATION

Background

Downhole steam generation (DSG) has gained considerable interest as a possible alternative to conventional surface generation of steam for oil recovery applications. Development of the process is currently proceeding along two parallel paths; the first to develop a direct, high-pressure generator, the second to develop an indirect, low-pressure system.

Both processes offer the advantage of generating steam within the injection well casing, directly adjacent to the sand face of the reservoir. This eliminates the substantial heat losses associated with surface steam distribution piping and downhole tubing, thus delivering more heat to the reservoir per unit of fuel burned.

The direct, high-pressure generator offers, in addition, other distinct advantages as follows:

1. Combustion gases are injected with the steam into the formation. This further increases the thermal efficiency of the process, reduces the attendant air pollution problems, and reportedly enhances oil recoveries.

2. The generator can be installed in conventional 180 mm (7 in) diameter well casing, whereas the indirect unit normally requires a minimum well diameter of 250 mm (10 in) (Reference 3-15).

Because of these advantages for the direct system, most industry attention is currently focused on the development of this alternative. It is the only process considered in this report.

Several companies and agencies are currently developing and/or marketing DSG technology. Some of these include Rockwell International Corp., Chemical Oil Recovery Co. (Corco), Trans Texas Energy, Vedette Energy Corp., and Sandia National Laboratories. While the design details vary somewhat between manufacturers, the basic process technology is similar for all direct, high pressure DSG's. As Corco was selected for the site visit conducted in this study, some of the process details described below are specific to their unit.

Process Description

The Corco direct, high-pressure steam generator design is based on a patent issued to Robert V. Smith in 1969 and assigned to Phillips Petroleum Company (Reference 3-16). The basic unit is illustrated in Figure 3-10. It consists of a cylindrical combustion chamber, surrounded by a water jacket, and a vapourizer or quench chamber. The entire unit is mounted in a section of well casing and is connected to the air, water, and fuel support systems located at the surface by means of transfer lines.

Fuel is ignited by means of a torch or spark igniter, after which the flame is self-supporting. Feedwater is preheated by passing through the water jacket, cooling the walls of the combustion chamber, prior to being sprayed into the flame, where it is converted to steam in the quench section. The steam/combustion gas mixture then exits the downhole open end of the generator and is forced into the formation.

The entire unit must operate at the steam injection pressure. Thus fuel, water, and combustion air must all be supplied at high pressure. Liquid fuels burning at high pressure with short residence times have a tendency to form soot particles due to incomplete combustion. This could ultimately lead to some formation plugging. Corco claims that the key to overcoming this problem is to ensure complete atomization of the fuel droplets. To achieve this, the combustor operates at approximately 3 percent excess oxygen, with air being supplied as follows:

1. A small amount of nozzle air is added with the fuel for preatomization in an air-blast atomizer.

2. Primary air (approximately 1/3 of the stoichiometric air requirement) is added through an inner swirling jet.

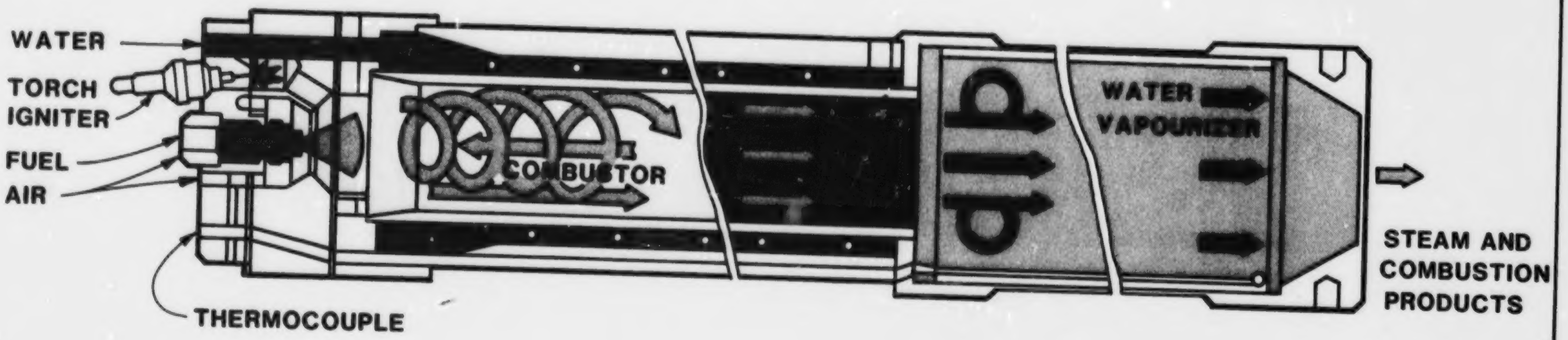

WATER
TORCH IGNITER
FUEL
AIR
THERMOCOUPLE
COMBUSTOR
WATER VAPOURIZER
STEAM AND COMBUSTION PRODUCTS

Figure 3-10
THE CORCO DOWNHOLE STEAM GENERATOR
(Courtesy of Chemical Oil Recovery Co.)

3. Secondary air (approximately 60 percent of the total air) is added through an outer jet in a reverse swirl pattern. This provides an air blanket along the wall of the combustor, preventing fuel deposition and coking.

These swirling flows reportedly create a central region of low pressure in the combustor which draws a portion of the combustion gases back into the flame promoting better mixing and more complete combustion (Reference 3-17).

Feedwater is circulated in a helical pattern through the water jacket which surrounds the combustor, preheating it to approximately 90°C (200°F). It is then injected into the gas stream in a radial pattern through 12 uniformly spaced holes. The water-to-fuel ratio can be controlled to produce any quality steam up to and including superheat. Caustic is added to the water to neutralize the acid formed by the scrubbing of sulphur dioxide from the combustion gases.

An oxygen inhibitor is also added for corrosion control.

Although not well documented, the water treatment requirements for DSG currently appear to the about the same as for conventional once-through systems (i.e., softening). While some claims have been made for the ability of the process to accept lower quality feedwater, this has not been demonstrated, and a review of the process concepts suggests this is unlikely. If the hardness components of the feedwater are not removed, they would likely precipitate as a scale either within the generator, in the casing perforations, or at the sand face, any of which would be highly undesirable. If the generator is to produce superheated steam, there must be a limit to the dissolved solids concentration which can be tolerated in the feedwater. Total evaporation of the feedwater means that all dissolved components will be converted to either particulate or molten salts, which may cause corrosion, erosion, or formation plugging problems if present at high concentrations.

The principal control element is a thermocouple located in the quench section. This monitors steam outlet temperature enabling the fuel/water ratio to be adjusted accordingly. Secondary control is provided by means of a sample port which sends combustion products to the surface for analysis. The steam is condensed and the water pH is measured for caustic feed control. Oxygen concentration is also measured for control of the air/fuel ratio.

The units are reportedly capable of burning both liquid fuels and gas. The ability to burn solid fuels is precluded both by the obvious difficulty of feeding such a material as well as the need to protect the formation from the deposition of ash particles on the sand face.

DSG claims thermal efficiencies in the order of 98 percent, because of the low heat losses associated with the process. However, as with other high-pressure combustion processes (e.g., WAO and Vapor Therm), there is a large energy requirement associated with the compression of combustion air. When this is taken into account, an overall energy conversion efficiency in the order of 78 percent is considered more representative. It should be recognized, however, that DSG delivers essentially all of the output heat energy to the formation. Other processes measure energy conversion efficiency only across the actual steam generation unit, and significant heat losses normally occur before the energy output from the unit actually reaches the sand face.

Process Equipment

Corco has the exclusive licence to manufacture and market the Phillips DSG for oil recovery applications. The standard unit is rated at approximately 2 MW (7 MM BTU/hr) and is about 1.8 m (72 in) long by 150 mm (6 in) outside diameter. It is totally constructed of Type 304 stainless steel and is completely modular with burner, combustion chamber, and quench chamber readily removable.

The major support equipment item required is the air compressor. This is normally trailer-mounted, gas or diesel driven, and is located adjacent to the injection well. The Corco unit is reportedly designed for pressures up to 10 MPa (1500 psi), but has only been tested in the 2 - 7 MPa (300 - 1000 psi) range to date.

Other support equipment including feedwater pumps, fuel preheater and pumps, and controls are typically mounted on a second trailer and likewise located adjacent to the injection well.

A service rig is used to place the generator in the well and remove it. The unit is normally held in place with a special downhole packer.

Demonstrated Performance

To date, Corco has conducted three field tests of their DSG in the Kern River field near Bakersfield, California. In these tests, the units burned lease crude and were supplied with softened, produced water. The tests were conducted on wells with a previous history of production on steam, in a cyclic stimulation mode. The tests reportedly showed a significant improvement in the oil/steam ratio as compared to the previous response by these wells using conventional steam injection.

Corco has attributed this improvement to two mechanisms. First, because of the higher quality steam delivered to the sandface, more heat is added to the reservoir per volume of steam injected. Secondly, the presence of nitrogen and carbon dioxide in the steam/gas mixture were believed to further enhance oil recovery by adding additional energy which increased reservoir pressure around the wellbore (Reference 3-18). The reader is referred to Appendix A for a discussion of the reservoir effects of injecting steam/combustion gas mixtures.

In general, DSG is in the very early stages of commercial demonstration, and several questions remain to be answered. These include the following:

1. What will be the long-term effects on oil production? Some have hypothesized that the increased production observed in short-term tests may be undermined in the long term by the breakthrough of nitrogen gas causing a decrease in reservoir pressure and subsequent drop in oil production.

2. What are the long-term effects of injecting small quantities of particulates (soot and salt particles) on the formation?

3. What corrosion and/or scaling problems are likely to be encountered when using different fuels or feedwaters?

4. Will atmospheric pollutants (e.g., SO_2, NO_x, CO) formed during combustion continue to be "scrubbed" by the reservoir in the long term?

5. Is the process an economic alternative to conventional steaming?

Environmental Impacts

One of the key reasons for a high level of industry interest in DSG is the hope that the process will reduce or postpone air pollution problems. Early test results of Corco and Sandia have both indicated that although high concentrations of SO_2 and NO_x were injected in the steam/gas mixture, very little was subsequently produced. This suggests that these compounds are dissolving in the formation water and/or the oil. Whether this phenomena will continue over the long term or whether combustion gases will eventually breakthrough and be vented from the casing of producing wells is undetermined at the present time.

DSG produces no liquid waste, with the exception of the water treatment wastes which would be similar to those associated with conventional steam generation.

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CHAPTER 4
STEAM GENERATION COSTS

INTRODUCTION

This chapter presents the results of a conceptual cost study into various types of steam generation/boiler feedwater treatment facilities required to support a small commercial or semi-commercial thermal recovery project in the Cold Lake Region of Alberta. For the purpose of the cost study a base case capacity of 73 MW (250 MM BTU/hr) was used. A steam generating facility of this size would be larger than most pilot projects but within the size range of equipment presently in the design stage. Mega-size in-situ projects may include multiples of the steam generation/boiler feedwater treatment facilities considered in this study.

Six types of steam generation equipment were considered in the cost study and these have been broken down into fourteen cases, depending on the type of fuel. The cases considered are as follows:

1. Conventional Once-through - Natural Gas Fuel
2. Conventional Once-through - Crude Fuel
3. Thermosludge - Natural Gas Fuel
4. Thermosludge - Crude-Fired
5. Multi-solids Fluidized Bed Combustor - Coal Fuel
6. Multi-solids Fluidized Bed Combustor - Coke Fuel
7. Wet Air Oxidation Unit, Air Process - Coal Fuel
8. Wet Air Oxidation Unit, Air Process - Coke Fuel
9. Wet Air Oxidation Unit, Oxygen Process - Coal Fuel
10. Wet Air Oxidation Unit, Oxygen Process - Coke Fuel
11. Downhole Steam Generators - Natural Gas Fuel
12. Downhole Steam Generators - Crude Fuel

13. Vapor Therm Steam Generators - Natural Gas Fuel
14. Vapor Therm Steam Generators - Crude Fuel

Complete system costs were developed for each facility including the cost of boiler feedwater treatment, steam generation, and waste disposal. Where possible, costs were scaled or prorated from known costs for similar facilities. In many cases, particularly for the developing technologies considered, such facilities have not yet been constructed, and thus actual installed cost figures were unavailable. In these cases, equipment vendor estimates were used in conjunction with established installation factors for similar types of facilities.

It is important to recognize that in a generic study such as this, the costs presented are intended to represent relative, order-of-magnitude values only. Given the early stage of development of several of the processes considered, it is premature to attempt to develop definitive cost estimates for commercial or semi-commercial scale facilities employing these technologies. However, with the information currently available, it is possible to gain some insight into the approximate relative costs of steam generation, using the processes considered in this study.

The order-of-magnitude estimates provided are only intended to be used for preliminary evaluation of alternatives, and should not be used for budgetary purposes. The general assumptions which were made in preparing these estimates are presented below, while the more detailed process-specific assumptions and estimating procedures which were used are outlined in Appendix B. They should be closely reviewed when using the cost data.

GENERAL ASSUMPTIONS AND CONDITIONS

The following is a list of assumptions which have been adopted or developed to form a basis for this cost study:

- All steam generation/boiler feedwater treatment facilities considered have been sized at approximately 73 MW (250 MM BTU/hr) heat capacity and have been rated at 14 MPa (2000 psi) and 335°C (640°F). Due to the depth of the oil-bearing formations in the Cold Lake region, pressures in this range have generally been required to obtain the desired injection rates.

- All steam generation facilities have been designed to support a cyclic steam stimulation recovery process. Although there has been pilot project work done on steam flooding, the cyclic steam or huff-puff operation has been more common. Conversion to a steam flood or other recovery process may be done after several years of operation.

- All steam generation/boiler feedwater treatment facilities have been costed complete with auxiliary facilities such as foundations, buildings, piping, controls, instrumentation, and electrical installations suitable for year-round operation in northern Alberta.

- All steam generation/boiler feedwater treatment facilities have been costed to comply with the regulations of the Alberta Boilers Branch, Electrical Protection Branch, Clear Air Act and Clean Water Act of Alberta.

- All steam generation/boiler feedwater treatment facilities would purchase electrical power from the local utility company. No on-site power generation has been provided.

- Capital costs have been developed based on verbal prices received by telephone conversations with equipment suppliers. In some cases, the prices received were "turn-key" type estimates which included all related facilities. In other cases, total plant costs were developed by using established factors for similar types of plant installations.

- Reuse of produced water with a composition similar to Esso, Cold Lake was assumed. Boiler feedwater treatment requirements were as follows:

  i) Fluidized-bed combustion, Vapor Therm, and downhole steam generation were assumed to have feedwater treatment requirements similar to conventional once-through steam generators. The treatment process used for cost estimating purposes is illustrated schematically in Figure 4-1.

  ii) The Thermosludge process was assumed to require de-oiling of produced water, as illustrated in Figure 4-2.

  iii) Wet air oxidation was assumed to require no pretreatment of produced water.

- All costs are reported in mid-1982 Canadian dollars.

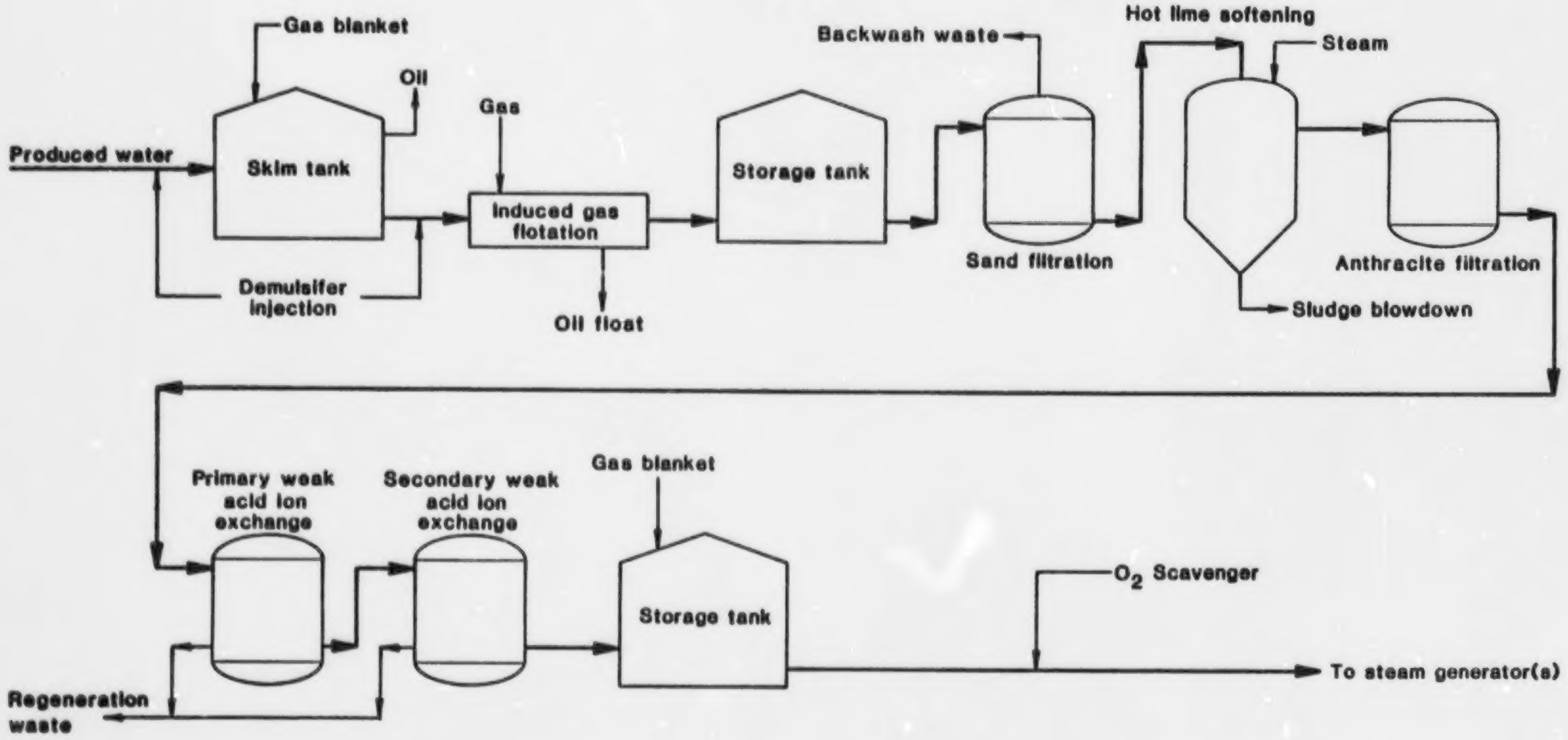
Gas blanket
Oil
Gas
Produced water
Skim tank
Induced gas flotation
Demulsifer injection
Oil float
Storage tank
Backwash waste
Sand filtration
Hot lime softening
Steam
Anthracite filtration
Sludge blowdown
Primary weak acid ion exchange
Secondary weak acid ion exchange
Gas blanket
Storage tank
O_2 Scavenger
Regeneration waste
To steam generator(s)

Figure 4-1
PROCESS SCHEMATIC FOR TREATMENT OF PRODUCED WATER TO ONCE-THROUGH STEAM GENERATOR FEEDWATER QUALITY

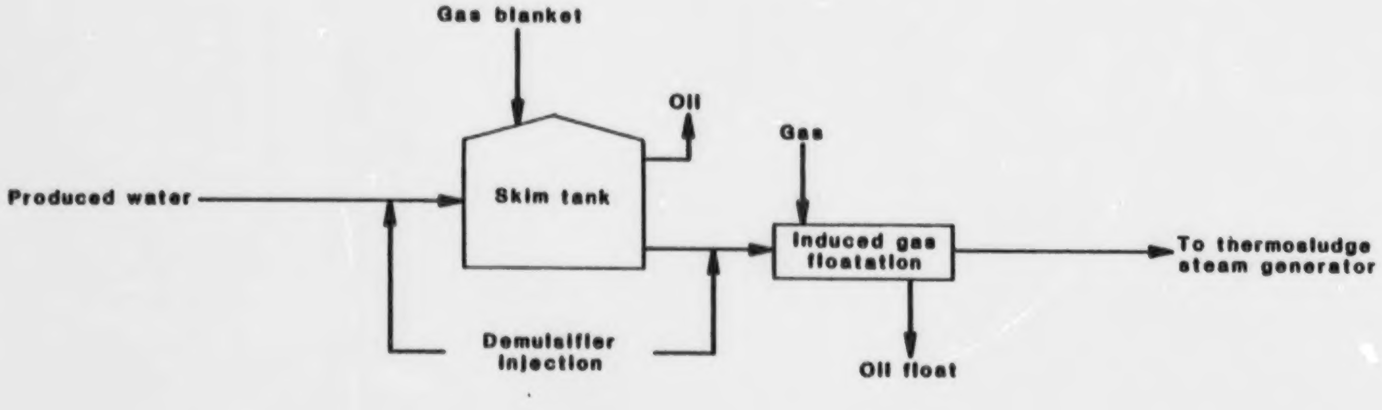
Gas blanket
Oil
Gas
Produced water
Skim tank
Induced gas floatation
To thermosludge steam generator
Demulsifier Injection
Oil float

Figure 4-2
PROCESS SCHEMATIC FOR TREATMENT OF PRODUCED WATER TO THERMOSLUDGE STEAM GENERATOR FEEDWATER QUALITY

Due to the generic nature of the capital cost estimate, a 20 percent contingency has been added. This is not considered to reflect the accuracy of the cost estimate but has been included to cover items not specifically identified in the conceptual design.

Operating costs have been developed based on unit costs received from CANMET or from estimates by suppliers. The following list summarizes the unit costs contained in the operating cost estimates.

1. Fuels

(a) Natural Gas - Sweet and Dry

Heating value	37.257 MJ/m³ (1000 BTU/scf)
Pipeline delivery pressure	700 kPa (100 psi)
Cost, at site boundary	$2.370/GJ ($2.50/Mscf)

(b) Crude Bitumen - Produced

Sulphur	4 - 5 percent
S.G.	0.971
Heating value	44.889 MJ/kg (19 300 BTU/lb)
Cost, in lease stock tank	$188.68/m³ ($30/bbl)

(c) Coke - from Suncor or Syncrude Plants

Sulphur	5 percent
Ash	8 - 10 percent
Heating value	31.980 MJ/kg (13 750 BTU/lb)
Cost, at site	$1.185/GJ ($1.25/MM BTU)

(d) Coal - Average, Plains Region, Sub-bituminous

Sulphur	0.5 percent
Ash	11.3 percent
Heating value	19.211 MJ/kg (8260 BTU/lb)
Cost, at site	$1.896/GJ ($2.00/MM BTU)

2. Limestone

Zero grind, 49 percent - 325 mesh

Cost, at site	$45/tonne ($40.80/ton)

3. Maintenance - calculated as a percentage of capital costs based on:

Compressor equipment	4 percent/yr
Major equipment	3 percent/yr
Auxiliary facilities	2 percent/yr

4. Electrical power

Demand charge	$2.30/KVA/month
Energy charge	$0.0125/kw-hr

5. Operators - includes all benefits	$135/day/person

6. Waste disposal

(a) Truck (small quantities/ short haul)	12 tonnes/load $100/load

(b) Rail (large quantities/ long haul) includes transfer of material to pit	$20/tonne

7. Miscellaneous - allocates a portion of total project overhead to the steam generation facilities	$75 000/yr

8. For the purposes of the operating cost estimate it has been assumed the plant would operate at full capacity for 330 days/year. This would allow for some down time (scheduled or unscheduled) and allow for periods where the plant would not operate at full capacity.

9. A contingency of 10 percent per year has also been added for each case to cover items not specifically identified at this stage.

10. Chemical costs:

	$/kg	$/lb
Lime	0.12	0.05
Soda Ash	0.37	0.17
Magnesium oxide	0.74	0.33
Sulphuric acid	0.11	0.05
Caustic acid	0.49	0.22
Polymer	4.48	2.00
Demulsifier	2.24	1.00
Corrosion inhibitor	4.93	2.25
Scale inhibitor	11.20	5.00
Oxygen scavenger	1.23	0.55

The reader is referred to Appendix B for detailed information regarding the assumptions and procedures used in preparing the cost estimates for each process considered in this study. The basis for each estimate is presented with a breakdown of the specific capital and operating cost components, and a discussion of the key factors affecting the cost of each process.

COST SUMMARY AND DISCUSSION

The capital and operating cost estimates for each of the fourteen cases considered in this study are presented in Table 4-1. It is readily apparent that the two processes currently in common use, conventional once-through and Thermosludge steam generators, are substantially less expensive than alternative processes from a capital cost perspective. While the Thermosludge process has minimal feedwater pretreatment requirements, the actual steam generation facilities are significantly more expensive than conventional once-through units, resulting in a slightly higher overall system cost. It is interesting to note that with produced water reuse, the feedwater pretreatment facilities represent a higher percentage of the total system cost than the actual steam generation facilities for the once-through case.

The wet air oxidation and fluidized bed combustion processes represent the highest capital cost alternatives. It should be noted, however, that greater economies of scale would be anticipated for these processes than for the alternatives considered. As both processes have solid-fuel firing capability, they require a substantial investment for solids handling equipment. The size of the solids handling facilities upon which the cost estimate was based would be the minimum size normally provided, yet they would be capable of handling two to four times the capacity without a significant increase in cost.

TABLE 4-1
STEAM GENERATION CAPITAL AND OPERATING COSTS
SUMMARY SHEET
($1 000)

ITEM	CONVENTIONAL ONCE-THROUGH		THERMOSLUDGE		MULTI-SOLIDS FLUID BED COMBUSTOR		WET AIR OXIDATION				DOWNHOLE		VAPOR THERM	
							AIR PROCESS		OXYGEN PROCESS					
	GAS-FIRED	CRUDE-FIRED	GAS-FIRED	CRUDE-FIRED	COAL-FIRED	COKE-FIRED	COAL-FIRED	COKE-FIRED	COAL-FIRED	COKE-FIRED	GAS-FIRED	CRUDE-FIRED	GAS-FIRED	CRUDE-FIRED
Capital Cost:														
Boiler feedwater treating facilities	$ 6 800	$ 6 800	$ 880	$ 880	$ 6 800	$ 6 800	$ -	$ -	$ -	$ -	$ 6 800	$ 6 800	$ 6 800	$ 6 800
Steam generator facilities	4 195	4 195	12 100	12 100	23 400	23 400	10 000	10 000	10 000	10 000	1 650	1 650	2 000	2 000
Air compression	-	-	-	-	-	-	16 100	16 100	25 000	25 000	16 100	16 100	16 100	16 100
BFW pumps	750	750	-	-	-	-	-	-	-	-	750	750	-	-
Fuel facilities	-	120	-	120	475	675	475	475	475	475	650	50	650	-
Miscellaneous	-	80	-	80	-	-	220	220	220	220	-	-	50	50
Contingency (20%)	2 690	2 730	2 640	2 680	6 475	6 515	5 360	5 360	7 140	7 140	5 530	5 410	5 460	5 330
Total	$14 435	$14 675	$15 620	$15 860	$37 150	$37 390	$32 155	$32 155	$42 835	$42 835	$31 480	$30 760	$31 060	$30 280
Operating Costs: (Per Year)														
Boiler feedwater treating (including 10% contingency)	$ 985	$ 985	$ 300	$ 300	$ 985	$ 985	$ -	$ -	$ -	$ -	$ 1 450	$ 1 450	$ 1 450	$ 1 450
Steam generation														
Fuel:														
Natural gas	5 695	-	6 435	-	-	-	1 545	1 545	-	-	6 220	1 545	6 550	1 545
Crude	-	10 415	-	11 765	-	-	-	-	-	-	-	8 550	-	9 150
Coke/Coal	-	-	-	-	5 080	3 175	4 500	2 815	4 500	2 815	-	-	-	-
Limestone	-	-	-	-	155	3 095	95	580	95	580	-	-	-	-
Maintenance	105	105	435	445	480	475	640	640	785	785	675	660	455	440
Electrical power	110	115	110	115	370	370	1 395	1 395	2 025	2 025	1 505	1 395	1 490	1 375
Operators	245	245	245	245	245	245	395	395	395	395	495	495	495	495
Waste disposal and misc.	75	75	125	125	240	1 685	220	285	220	285	75	75	125	125
Rental fees	-	-	-	-	-	-	-	-	-	-	-	-	4 320	4 320
Contingency (10%)	620	1 095	735	1 270	660	905	880	765	805	690	920	1 275	910	1 315
Total	$ 7 835	$13 030	$ 8 385	$14 265	$ 8 215	$10 935	$ 9 670	$ 8 420	$ 8 825	$ 7 575	$11 340	$15 445	$15 795	$20 215

It is apparent that the capital cost of the WAO/O_2 process is substantially higher than the WAO/air process, due to the provision of an oxygen plant. Alternatively, it would be possible to purchase oxygen "over-the-fence" which would decrease the capital cost but increase the operating cost of the facility.

The downhole steam generation and Vapor Therm processes appear to have similar capital costs. However, it should be recognized that the Vapor Therm equipment is normally leased, not sold, and thus the capital cost of the facility allows only for installation, not purchase, of the units. Lease costs are treated as an operating expense.

On an operating cost basis, the conventional gas-fired once-through steam generator and coke fuelled WAO/O_2 process represent the lowest cost systems. Despite the higher capital cost, the WAO/O_2 process offers substantial operating cost savings compared to the WAO/air alternative, due to lower overall energy requirements.

The principal reason for the relatively low operating cost of the coke-fired WAO/O_2 process is the low cost of fuel. While the coke-fired FBC process has similarly low fuel costs, this benefit is largely offset by the high limestone requirements associated with this high sulphur fuel. Preliminary tests indicate that the circulating bed designs proposed by Pyropower Corp. and Struthers/Battelle may be able to achieve adequate sulphur capture with high sulphur petroleum coke at Ca/S ratios lower than those assumed in this study. If this proves to be the case, the coke fuelled FBC process would be competitive with the gas-fired once-through generator and coke fuelled WAO/O_2 process from an operating cost perspective.

Due to lower thermal efficiencies and thus higher fuel costs, the Thermosludge process is somewhat more expensive to operate than the conventional once-through steam generator, despite the lower feedwater treatment costs.

High air compression costs contribute to high operating costs for both the downhole steam generation and Vapor Therm processes. Both must also burn higher-cost fuels (gas and oil) as compared to the WAO and FBC processes. The Vapor Therm process operating costs are particularly high due to the inclusion of lease costs as an operating expense.

Annualized costs for each of the fourteen cases are presented in Table 4-2. In developing these costs, the following assumptions were made:

- Interest rate of 20 percent per annum
- Plant life of 25 years
- Straight line depreciation over 25 years

Table 4-2 also presents the annualized cost of steam in $/GJ for each of the cases investigated. On an annualized basis, estimated steam costs vary from a low of $5.40/GJ for the gas-fired, conventional once-through steam generator to $13.15/GJ for the Vapor Therm process.

In reviewing the relative costs of steam generated by each of the processes, it is important to keep several factors in mind. First, no cost credit has been assigned to the WAO, Vapor Therm, or DSG processes to account for the incremental increase in oil production or production rate which may be anticipated due to the injection of combustion products with those processes. Ultimately, it will be necessary to compare the actual cost of oil production by each process (i.e., $/m^3 of oil produced). However, this cannot be done until more reliable estimates can be made of the effects of combustion-gas injection on oil recoveries.

TABLE 4-2
ANNUALIZED STEAM GENERATION COSTS

ITEM	CONVENTIONAL ONCE-THROUGH		THERMOSLUDGE		MULTI-SOLIDS FLUID BED COMBUSTOR		WET AIR OXIDATION				DOWNHOLE		VAPOR THERM	
							AIR PROCESS		OXYGEN PROCESS					
	GAS-FIRED	CRUDE-FIRED	GAS-FIRED	CRUDE-FIRED	COAL-FIRED	COKE-FIRED	COAL-FIRED	COKE-FIRED	COAL-FIRED	COKE-FIRED	GAS-FIRED	CRUDE-FIRED	GAS-FIRED	CRUDE-FIRED
Annualized Capital Cost:														
Annual payment on capital ($1 000)	$ 2 918	$ 2 966	$ 3 157	$ 3 206	$ 7 509	$ 7 557	$ 6 499	$ 6 499	$ 8 658	$ 8 658	$ 6 365	$ 6 215	$ 6 278	$ 6 120
Depreciation ($1 000)	577	589	623	634	1 486	1 498	1 286	1 286	1 712	1 712	1 260	1 230	1 242	1 210
Annual operating cost ($1 000)	7 835	13 030	8 385	14 265	8 215	10 935	9 670	8 420	8 825	7 575	11 340	15 445	15 795	20 215
Total annualized cost ($1 000)	$11 330	$16 585	$12 165	$18 105	$17 210	$19 990	$17 455	$16 205	$19 195	$17 945	$18 965	$22 890	$23 315	$27 545
Steam Cost $/GJ	$5.40	$7.95	$5.80	$8.65	$8.25	$9.55	$8.35	$7.75	$9.20	$8.55	$9.10	$11.00	$11.15	$13.15

Assumptions:

- Interest rate of 20 percent per annum
- Plant life of 25 years
- Straight-line depreciation over 25 years

Secondly, while the cost of steam produced by downhole steam generation appears relatively high, the quality of steam and actual heat delivered to the reservoir may be significantly higher than with alternative processes, because surface losses are avoided.

Those processes which inject combustion gases to the reservoir (e.g. WAO, Vapor Therm, and downhole steam generation) or which reduce atmospheric emissions (e.g., FBC) provide a significant advantage from an environmental perspective which is not considered in the cost analysis.

Finally, the cost of fuels will have a profound effect upon the cost analysis. Natural gas still enjoys an advantageous pricing position in western Canada compared to most regions of North America. However, if gas escalates more rapidly than solid fuels, as predicted, those processes with solid-fuel firing capability will become increasingly attractive. This will be particularly true of those capable of burning petroleum coke in an environmentally acceptable and cost effective manner. Increasing quantities of this fuel are likely to be produced in future in close proximity to the heavy oil producing regions of western Canada. As this occurs, these processes will undoubtedly realize significant cost advantages.

CHAPTER 5
RECOMMENDATIONS FOR FUTURE WORK

INTRODUCTION

One of the objectives of this study was to identify the need for research and development work required to promote the commercialization of alternative steam generation technologies for oil recovery. This chapter presents recommendations for laboratory and field studies which should be undertaken to further such development efforts, as well as some suggestions for process design modifications for future consideration.

A further objective of the study was to identify possible industrial partners for participation in share-cost funding of the recommended laboratory or field studies. It was concluded that such partners would likely come from one of two industry sectors; the resource development industry - specifically those firms with proposed or in-place thermal EOR projects; or steam generation equipment manufacturers and vendors. Accordingly, a list of contacts within each industry sector was developed and is presented in this chapter.

RECOMMENDED RESEARCH AND DEVELOPMENT

Two categories of recommended research and development studies were identified; general studies, the results of which would be applicable to several of the processes considered; and, process-specific studies pertaining to each of the steam generation technologies reviewed. The proposed studies within each category are described below.

General Studies

Several of the processes reviewed (i.e., wet oxidation, Vapor Therm, downhole steam generation) are designed for the injection of a steam/combustion gas mixture to the reservoir. While all claim to offer several advantages, particularly with regard to improved oil recoveries and the reduction or elimination of air pollution problems, the actual benefits to be derived from such processes have yet to be clearly demonstrated. While virtually all preliminary field tests and mathematical simulations of these processes conducted to date have indicated that some improvement in oil recoveries and production rates are likely, there has been no concensus as to the extent of improvement which can reasonably be anticipated. Predicted increases in oil recoveries have varied from 30 percent to 900 percent, with even the lower estimates being questioned by some.

The principal reason for such discrepancies would appear to be the fact that there is very limited actual test data available on which to base these claims. The few field tests which have been run, have generally been short term and/or have been conducted under loosely controlled conditions. As a result, it is difficult to draw reliable comparisons to production with steam alone or to estimate long-term improvements in oil recoveries.

Several important questions remain to be answered. These include the following:

1. What improvements in ultimate oil recoveries and rate of oil production can reasonably be expected?

2. What will be the effects, if any, on the reservoir and on the produced oil characteristics of injecting particulates and acidic combustion gases (e.g., SO_2 and CO_2)?

3. What effect will the use of oxygen have, versus the use of air to support combustion?

4. Will the reservoir continue to scrub pollutants from the combustion gases over the long term, or will breakthrough or saturation ultimately occur, accompanied by venting of these gases from producing wells?

Two levels of research and development study requirements are envisioned as necessary to address the above questions. First, laboratory work with scaled or semi-scaled physical models is required to gain a better understanding of the mechanisms involved in steam/combustion gas injection for oil recovery. A more complete description of the research requirements in this regard is provided in Appendix A. Second, a pilot scale field project is required in which steam and steam/combustion gas injection methods can be operated in parallel under tightly controlled experimental conditions. This will provide important information regarding the long-term effects which can be anticipated under actual operating conditions, as well as a more realistic indication of the relative economics of the two process concepts.

Another concern regarding steam/combustion gas injection which must be addressed relates to potential corrosion problems associated with the transportation of corrosive combustion products in steam distribution systems. Some products of combustion, particularly carbon dioxide and sulphur dioxide, form acidic solutions which are very aggressive to carbon steel in a wet steam environment. This problem is likely to be further aggravated in these processes due to the presence of excess oxygen in the combustion gases. Several solutions to the problem have been proposed including superheating of the product steam to prevent condensation, the addition of corrosion-inhibiting chemicals, and the use of special alloy steam distribution piping. Studies are required to determine the most cost-effective manner of addressing this problem.

To meaningfully evaluate the viability of steam/combustion gas injection methods for oil recovery, ultimately it will be necessary to compare the cost of oil production by these techniques to conventional steam injection methods. This cannot be accurately done until the total cost/benefit analysis is completed. This will necessitate the completion of the studies outlined above to generate information regarding the necessity and cost of special corrosion-prevention or flue gas clean-up measures, and the effects on oil recoveries and production rates. When this information is available, a more detailed comparative economic analysis of these processes should be undertaken than is currently possible.

Process-Specific Studies

Research and development work recommended for each of the specific steam generation processes considered in this study is presented below, by process.

Thermosludge Steam Generation Process

The Thermosludge system is considered to be a fully demonstrated, commercial steam generation process. Its failure to gain widespread acceptance within the oil industry is attributed primarily to the unfavourable economics associated with the process, rather than significant technical problems. Conventional, once-through steam generators have exhibited thermal efficiencies 10 to 15 percent higher than the Thermosludge system resulting in a significant competitive edge for the former, primarily due to lower fuel costs.

The indirect heating design of the Thermosludge system would appear to be ideally suited to conversion to solid fuel-firing. The external furnace which heats the eutectic salt mixture could be designed to burn solid fuels. The economics of such a design modification need to be investigated. If favourable, it may be possible to couple the fluidized bed combustion (FBC) and Thermosludge techniques to develop a process which not only has minimum feedwater pretreatment requirements, but is capable of burning low grade solid fuels with acceptable atmospheric emissions. The relatively low cost of solid fuels may help offset the economic penalty associated with the lower thermal efficiency of the process.

Likewise, development of the Thermosoft water treatment process would enable the advantages of the higher thermal efficiencies of conventional steam generators to be coupled with the relatively simple Thermosludge water softening concept. Alternatively, the Thermosoft water treatment process could be used to supply feedwater to a once-through FBC steam generator, thus enabling solid fuels to be burned, while reusing produced water with relatively low pretreatment requirements.

Considerable development work is required on the Thermosoft process before such design concepts can be seriously considered. Laboratory bench scale and pilot studies are required to determine what pretreatment for oil removal is required ahead of the process, what residual hardness concentrations will be attainable, whether silica reduction is required and if so what removal levels can be achieved, and what post-treatment (i.e., filtration and/or ion exchange polishing) is required. Following this work, a small-scale field demonstration project will be required to assess the stability of the process under actual operating conditions and the overall economics of the technology.

Fluidized Bed Combustion

The FBC process is in an early demonstration stage in oil recovery applications. While the basic FBC combustion/steam generation technology is reasonably well established, there are specific areas which warrant further research and development. The first relates to the necessity for silica reduction in the feedwater treatment process. There is considerable controversy regarding the necessity for silica removal in once-through steam generator systems. While vendors have historically recommended a reduction in feedwater silica concentrations to less than 50 mg/L, some recent experience indicates that considerably higher concentrations can be tolerated. However, only limited experience is available to date at high steam pressures (14 MPa (2000 psi) and above), and the long-term effects on steam generator performance is still undetermined. If indeed the feedwater silica specification can be relaxed, the pretreatment requirements for western Canadian produced waters will be significantly reduced, resulting in a simpler, and less expensive process for reuse of produced water. More data on the operation of high-pressure, once-through steam generators at high silica concentrations is required to establish that less stringent feedwater specifications will not be detrimental to their long-term performance.

A limitation, which has beset conventional FBC systems is their requirement for exceptionally high Ca/S ratios to achieve satisfactory SO_2 capture when burning particularly high sulphur fuels. This has resulted in high operating costs associated with the high sorbent requirements and the disposal of correspondingly large quantities of FBC residue. This could seriously limit the ability of the process to utilize high-sulphur petroleum coke as a fuel. However, some recent tests indicate that the recirculating bed designs employed by Struthers/Battelle and Pyropower significantly improve limestone utilization, thereby reducing sorbent requirements. Demonstration tests with petroleum coke should be run to estimate what range of Ca/S ratios are likely to be required to meet Canadian atmospheric emission guidelines.

The large quantities of solid waste generated by the FBC process have been cited by some as an environmental issue which should be addressed in the development of this technology. As a result, some investigations have been conducted into the possibility of waste utilization as well as the development of safe disposal practices for the material. While preliminary findings have been encouraging, particularly with regard to by-product utilization, considerably more work is required in this area.

Wet Oxidation

While wet oxidation has been commercially demonstrated for waste treatment, the process is still in the early stages of development for steam generation for oil recovery. The process holds considerable promise, provided certain issues can be resolved. First, as the process injects combustion gases with the product steam, the general studies outlined earlier in this chapter should be undertaken, particularly to evaluate the impact on oil recoveries and to assess the most appropriate measures for corrosion protection in steam distribution piping. As the process apparently does not produce SO_2 or NO_x, studies related to the fate of these air pollutants do not appear to be necessary. The use of oxygen, as opposed to air, to support combustion should be closely examined however, as this design modification will have a significant impact on capital and operating costs and preliminary indications suggest it will also affect oil recoveries.

Another important issue, which must still be addressed, relates to the handling of the liquid blowdown stream from the process. Further work is required to characterize the liquid and solid wastes from the process and to determine appropriate treatment and disposal practices for this material.

As outlined in Chapter 3, several different wet oxidation process and reactor designs have been used or proposed in waste treatment applications with each claiming to offer particular advantages. A detailed review of these alternatives would appear to be worthwhile to ensure that the Zimpro WAO single-stage, unstirred reactor is indeed the most economic and the most appropriate vessel to use in this particular application.

As illustrated in Chapter 2, the chemistry of produced waters varies considerably from location to location and at a single location over time. The ability of the WAO process to accept such a wide range of feedwater qualities without corrosion or scaling problems or process unstability has yet to be demonstrated. A field-operated pilot plant is required to confirm the ability of the process to handle untreated produced water of variable composition.

Vapor Therm

The Vapor Therm process has been commercially operated for steam generation in oil recovery applications since the mid to late 1970's. While some further sophistication of the instrumentation and control system would seem appropriate, the process can otherwise be considered a commercial steam generation technology.

Like the wet oxidation process, Vapor Therm produces a steam/combustion gas mixture for injection to the formation. Thus, the general studies outlined earlier in this chapter are required to fully assess the impacts and economics of this concept.

While the Vapor Therm process has not been operated on produced water to date, it would appear to be capable of accepting a softened produced water supply. As steam is generated by combustion gas quenching rather than by heat exchange across a heat transfer surface, the problems associated with moderate scale formation would seem to be less critical. As a result, silica removal may be unnecessary, thus simplifying the water treatment process for reuse of produced water as compared to conventional once-through steam generators.

Downhole Steam Generation

Downhole steam generation is in the early stages of demonstration. While some preliminary field tests have been conducted, these have been relatively short term and have not yet demonstrated what long-term effects may be expected from the injection of steam and combustion products to the reservoir. The general studies outlined earlier are required to make this evaluation.

The issue of long-term operation in a superheated steam mode should also be addressed. If produced water is to be reused, production of superheated steam means that total evaporation of the feedwater will result in the production of dried salts. These may contribute to corrosion, erosion or formation plugging problems in the long term, thus necessitating operation at lower steam quality or the use of low TDS feedwater.

One of the criticisms levelled at downhole steam generation has been the cost and effort associated with running the unit in and out of the well. This makes maintenance more difficult and renders the process not particularly well suited to cyclic steam stimulation applications. As an alternative, some vendors have investigated placing the unit at the top of the hole with an insulated tubing string. The economics of this alternative need to be evaluated to determine whether this concept is competitive with the use of larger, centralized surface steam generation and distribution alternatives.

POTENTIAL INDUSTRIAL PARTNERS

Several organizations and individuals were contacted during the course of this study both to gain information regarding the development of the steam generation technologies considered, and to discuss possible interest in participation in future share-cost laboratory or field demonstration programs with CANMET. Industry contacts are listed below in two categories; the resource development industry, and equipment manufacturers and vendors. Personnel listed would be the principal contacts in the areas addressed by this study.

Resource Development Industry

Husky Oil Ltd.
Calgary, Alberta
Mr. T. Vonde - Manager Enhanced Oil Recovery (403) 825-1196
Mr. H.J. Berry - Vice-President, Heavy Oil (403) 267-6111

Shell Canada Resources Ltd.
Calgary, Alberta
Mr. D. Komery - Manager Commercial Project (403) 232-3111

Petro Canada Ltd.
Calgary, Alberta
Mr. S. Chakrabarti, Chief Project Engineer (403) 232-6897
Dr. G. Derbowka, Director of Research (403) 270-2400

Esso Resources Canada Ltd.	
Calgary, Alberta	
Dr. R. Butler, Manager Heavy Oil Research Division	(403) 259-0671
Mr. G. Mainland, Engineering Manager Heavy Oil	(403) 237-3737
Texaco Canada Ltd.	
Calgary, Alberta	
Dr. D. Livesey, Research Associate	(403) 267-0617
Mr. R. Bialek, Assistant Chief Oil Sands Engineer	(403) 267-0617
Cold Lake Heavy Oil Ltd.	
Calgary, Alberta	
Mr. H. Aiken	(403) 245-9300
Union Oil Company of Canada Ltd.	
Calgary, Alberta	
Mr. T.C. Presber, Heavy Oil Manager	(403) 268-0511
Alberta Energy Co.	
Calgary, Alberta	
Mr. Paul Carr, Manager Heavy Oil Development	(403) 266-8111
BP Exploration Canada Ltd.	
Calgary, Alberta	
Mr. Dave Foxley, Oil Sands Research Coordinator	(403) 237-1234

Equipment Manufacturers and Vendors

Company: KTI Gas Processors
Santa Ana, California
(714) 835-6660
Process: Thermosludge Steam Generator
Prime Contacts: Mr. E.E. Wittmeyer, Senior Process Engineer
Mr. C. Neshat, Project Manager
Mr. P. Stewart, Vice President, Sales

Company: Struthers Thermo-Flood Corp.
Winfield, Kansas
(316) 221-4050
Process: Multi-Solid Fluidized Bed Steam Generator
Prime Contact: Mr. W.W. Young, Vice President and General Manager

Company: Pyropower Corporation
San Diego, California
(714) 455-3840
Process: Circulating Fluidized Bed Combustion System
Prime Contact: Mr. J.E. Cook, Marketing Manager

Company: Zimpro-AEC Ltd.
Wausau, Wisconsin
(715) 845-9251
Calgary, Alberta
(403) 266-8111
Process: Wet Air Oxidation
Prime Contacts: Mr. L. Pradt, General Manager
Mr. C.L. Soukup, Manager, Energy Sales
Mr. J. Mullis, Canadian Sales Manager

Company: Ontario Research Foundation
Mississauga, Ontario
(416) 822-4111
Process: Wet Air Oxidation
Prime Contacts: Dr. R. Laughlin, Assistant Director
Mr. H. Robey, Assistant Research Scientist

Company: Carmel Energy, Inc.
Process: Vapor Therm Steam Generator
Prime Contacts: Mr. V.R. Young, Petroleum Engineer
Deerfield, Missouri
(417) 228-1050

Mr. J. Sperry, Vice President
Houston, Texas
(713) 960-0922

Company: Chemical Oil Recovery Co. (CORCO)
Bakersfield, California
(805) 322-6059
Process: Downhole Steam Generator
Prime Contact: Mr. S.K. O'Nesky, Project Engineer

Company: Rocketdyne Corp.
Canoga Park, California
(213) 710-3037
Process: Downhole Steam Generator
Prime Contacts: Mr. J. Fiefeld
Mr. D. Wright

CHAPTER 6
SUMMARY AND CONCLUSIONS

SUMMARY

Most steam injection projects for oil recovery in western Canada currently utilize conventional, once-through steam generators producing wet (80 percent quality) steam. These burn oil or natural gas and require a feedwater supply that is free of oil and hardness and contains silica concentrations of less than 50 mg/L. These generators typically discharge their combustion gases directly to the atmosphere, without treatment of flue gas. While they are capable of reusing produced water, it must first be subjected to a relatively sophisticated treatment process for removal of the above noted constituents.

Alternative steam generation technologies have been demonstrated or proposed which offer one or more of the following advantages:

1. They burn low-grade solid fuels (e.g., coal and petroleum coke).

2. Feedwater pretreatment requirements are minimal.

3. Combustion gases are injected to the oil-bearing formation or the concentrations or air pollutants which they contain are substantially reduced.

In addition, some of these processes claim to exhibit higher energy conversion efficiencies, while others are reported to improve oil recoveries as compared to conventional steam injection. Steam generation processes currently at bench, pilot, or commercial stages of development which fulfilled any of the three criteria listed above were identified and screened to select those with the greatest potential for future development and application to thermal oil recovery. The five processes with the greatest apparent potential included:

1. Thermosludge Steam Generation
2. Fluidized Bed Combustion
3. Wet Oxidation
4. Vapor Therm
5. Downhole Steam Generation

Conclusions regarding the potential for large-scale application of each of the above processes to thermal recovery of oil in western Canada are presented below.

CONCLUSIONS

Large-scale application of the Thermosludge steam generation process in western Canada appears unlikely. Despite the fact that feedwater pretreatment requirements are minimal, economics will generally favour the use of conventional once-through steam generators because of their higher thermal efficiencies. This will be particularly true as the size of oil recovery projects increases, and the incremental cost of expanding the capacity of feedwater pretreatment facilities for conventional steam generators decreases. A design concept which would appear to be worth pursuing is the development of a solid-fuel-fired Thermosludge process. The lower cost of a solid fuel may be sufficient to offset the economic penalty associated with the lower thermal efficiency of the process.

The fluidized bed combustion (FBC) process does appear to have potential for application in western Canadian oil recovery projects, particularly those of "mega" scale.

While small FBC facilities are clearly uncompetitive with conventional steam generators, the process offers substantial economies of scale. In addition, FBC is extremely versatile and is ideally suited to a large thermal recovery and upgrading operation which may have numerous requirements for steam of varying quality, process heat, electric power generation, etc. The ability of the process to burn petroleum coke which may be produced as a by-product at an onsite upgrader would be a further economic advantage. The control of atmospheric emissions, inherent in the design of the FBC process, will also enhance the environmental acceptability of the process.

The wet air oxidation process appears to offer more advantages than any of the steam generation processes considered in this study. It apparently requires no feedwater pretreatment for the reuse of produced water, it has the capability to burn low-grade solid fuels, it produces no air pollutants, and it injects a steam/CO_2 mixture to the formation which is believed to improve oil recovery. For these reasons it has generated considerable interest within the oil industry. If field demonstration of the process bears out the preliminary laboratory test results, the technology may well find widespread application to several intermediate scale thermal recovery projects in western Canada.

The Vapor Therm and downhole steam generation processes are similar in concept but differ with regard to equipment design. Both burn oil or natural gas, quench combustion gases in a water spray, and inject a steam/flue gas mixture to the reservoir. They differ with respect to their philosophy regarding the relative advantages and disadvantages of surface-located facilities versus downhole equipment. While the process concept has merit, the economics would appear to favour alternative technologies unless the process can demonstrate substantial improvements in oil recoveries.

APPENDIX A

RESERVOIR EFFECTS OF STEAM PLUS COMBUSTION GAS INJECTION

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SUMMARY

The principal objective of this chapter is to assess the state-of-the-art of carbon dioxide and/or nitrogen injection with steam in the cyclic stimulation and flood type processes. The intent is to examine the applicability this type of recovery process to reservoirs in western Canada. Economic aspects are not considered.

Very little information is currently available on carbon dioxide/steam injection based upon field tests (none reported) and laboratory experiments (very few so far, at the University of Alberta). Computer simulations have rather severe limiting features in view of the absence of fracture simulation and great uncertainty in relative permeability data. Within these restrictions, it seems that carbon dioxide, injected with steam would have a beneficial effect on oil recovery (about 30 percent increase) when used with steam in cyclic stimulation, and in particular, in steamflooding.

Limited laboratory data have been reported for flue gas injection with steam. Several short duration field tests involved flue gas injection with steam. Results do not seem to be promising in spite of somewhat extravagant claims. Computer simulations of flue gas injection with steam in cyclic stimulation show poorer performance compared with steam alone. The situation is slightly better in the case of steamflooding. It appears that the presence of nitrogen promotes gravity override of steam, thus lowering its displacement efficiency in most cases. In a field project, production of large volumes of nitrogen may lead to gas locking, erosion, reduced liquid flow, gas breakthrough, etc. Furthermore, from a mechanistic standpoint, presence of a noncondensible gas would make the stable steam drive process unstable.

On the whole it seems that flue gas injection is likely to have a greater chance of success in steamflooding as opposed to cyclic steam stimulation.

Field tests of the process show that the reservoir rock effectively removes nearly all of the sulphur and nitrogen oxides, thus alleviating the pollution problems associated with steam generators.

Solvent injection with steam has been tested in the laboratory, and also in rather small field tests. The process could be efficient for the recovery of highly viscous oils, such as the Athabasca bitumen. However, the use of a costly material such as a solvent would have to be justified.

Turning to in-situ combustion, there is much talk of using oxygen in place of air in combustion. Very little laboratory data and no field data have been reported on the process. It seems that oxygen has a good chance of success if the oil recovery performance is substantially better than that observed in conventional combustion. This does not appear to be the case. In any event much research is needed in this area.

Generally speaking, flue gas injection with steam might have some application in the thin Lloydminster reservoirs, while carbon dioxide injection with, and preferably prior to, steam is more likely to be applicable in the Cold Lake reservoirs.

Research in Canada on the aforementioned processes is virtually nil.

THERMAL RECOVERY IN WESTERN CANADA

GENERAL

At the present time, over 50 thermal recovery projects are in operation in western Canada. Apart from that, at least two mine-assisted recovery projects and one electrical heating project are under planning and/or operation. Among non-thermal heavy oil recovery methods, a caustic flood was conducted and recently suspended in the Sparky Sand in Lloydminster. Many other recovery projects have been previously conducted. At least three major semi-commercial steam pilots are in operation as well as one major combustion project. These are Shell's Peace River project, Esso's Leming and Bourque projects, and Mobil's Battrum project. A dozen comparable projects are in various stages of planning at this time.

It is quite clear that thermal oil recovery activity in western Canada is on the upswing. This reflects foresight on the part of the operators as many of these projects probably are or will be modestly profitable in view of the world oil prices guaranteed.

RECOVERY METHODS

The most important thermal recovery methods being employed in western Canada are cyclic steam stimulation and wet combustion. Steamflooding has not been as successful in Cold Lake; a variation of the process is being used in Peace River. Steamfloods are also in operation in Saskatchewan, where the experience shows that using the latest technology of steam injection, it is possible to use steamflooding successfully in the same reservoirs where it failed in the sixties. The Aberfeldy steamflood is the prime example.

Cyclic steam stimulation has been quite successful in the Cold Lake area, and to a lesser extent in other areas. Typically, steam is injected at 8-10 MPa (1200-1500 psi), often at 14 MPa (2000 psi) into formations which are about 460 m (1500 ft) deep, at rates on the order of 6.6 m^3/h (1000 B/d) water equivalent. As a result, formation parting occurs, and it becomes possible to inject large slugs of steam, on the order of 8000 m^3 (50 000 bbl). Subsequently, the well is turned to production. On the whole, oil-steam ratios of 0.25 to 0.5 m^3/m^3 have been achieved (Buckles, Reference A-1).

Steamflooding has been tested only to a limited extent at Cold Lake. The author's numerical simulations show that the oil-steam ratios in a flood would be approximately one-half of the values given above to cyclic steam stimulation, which would render such an operation marginal or unprofitable. Nevertheless, sometime in the future it would become imperative to employ steamflooding in the cyclically stimulated reservoirs, where the recoveries are less than 10 percent of the oil in place.

In-situ combustion has been in use for the past 15 years in Saskatchewan. The three major projects are Battrum, Golden Lake, and Aberfeldy. Battrum is a wet combustion project in a 70-cP oil, and produces about 46 m^3/h (7000 B/d). The low oil viscosity is responsible for the success of the project. Indeed in-situ combustion has been more successful in light than in heavier oil formations in most cases. Golden Lake and Aberfeldy oil viscosities range from 100 to 6000 cP. Combustion has been a marginal operation in these reservoirs.

At the present time, about 20 of some 50 thermal projects utilize in-situ combustion, while the remainder involve cyclic steam stimulation or steamflooding (in a few instances).

EFFECT OF INJECTING GASEOUS ADDITIVES WITH STEAM

INTRODUCTION

Injection of various types of additives - gases, surfactants, solvents, etc. - with steam has been proposed from time to time. In some instances, e.g., Cold Lake, it was considered as a possible means of increasing oil recovery in cyclic steam stimulation, in other cases, e.g., downhole steam generators, injection of combustion gas with steam is more or less unavoidable. Other uses of additives include sludge inhibition, emulsion breakdown, clay control, etc., within the formation as well as in the wellbore.

In the following, we shall consider the use of gaseous additives, in particular flue gas, with steam, referring to field experience, laboratory results, and numerical simulation studies. We shall first discuss injection of natural gas because it permits a clearer understanding of the process.

NATURAL GAS INJECTION WITH STEAM

During the early seventies, Imperial Oil experimented with natural gas injection with steam in the Cold Lake Clearwater formation. They tested gas injection prior to steam injection, with steam, and also later in the production phase of the cycle, all in the context of cyclic steam stimulation. It is known that gas injection was effective in increasing oil recovery, but it was not cost effective. An understanding of the results can be obtained from laboratory data reported by Pursley (Reference A-2). He used a scaled model of the reservoir formation, with a drainage radius of 74 m (242 ft.) corresponding to 2 ha (5 acre) spacing. Gas (methane, air, or carbon dioxide) was injected when the productivity of the well had substantially declined. The injected gas-steam ratio was 3.3 Nm³/m³ (20 scf/bbl). Figure A-1 shows a marked improvement in oil-steam ratio as a result of injecting methane or air. Carbon dioxide was less effective, possibly because of its solubility in water. Water-oil ratio also reduced as a result of gas injection. For example the water-oil ratios were 1.7 for air, 1.8 for methane, 2.4 for carbon dioxide, as compared with 3.2 for steam alone. It was noted that while using air, combustion occurred spontaneously in the field, although it was not noticed in the laboratory model. This caused damage to wellbore equipment and severe emulsion problems. As a result, gas was used subsequently in the field test.

Two two-cycle tests were carried out to compare gas injection immediately after steam with gas injection late in the production phase. Steam slugs were 3200 m³ (20 000 bbl) and 4800 m³ (30 000 bbl), with gas-steam ratios of 3.3 Nm³/m³ (20 scf/bbl). Figure A-2 shows that performance improvement was greater when gas (methane) was injected immediately after steam rather than late in the production period. Figure A-3 shows similar results for varying gas-steam ratios. It is seen that the optimum injected gas-steam ratio is in the range of 17-33 Nm³/m³ (100-200 scf/bbl). These laboratory results were said to be in qualitative agreement with field results.

The author has carried out some two thousand steam simulations using a compositional steam injection simulator. Many of these were conducted for Cold Lake formations. In a series of runs, natural gas injection with, before and after steam was examined. The difference in performance in the three cases was quite small. For example, the overall oil-steam ratios were 0.10, 0.123, and 0.137, respectively for the three cases. The oil-steam ratio in the absence of gas was 0.05 to 0.20. Figure A-4 depicts oil production performance

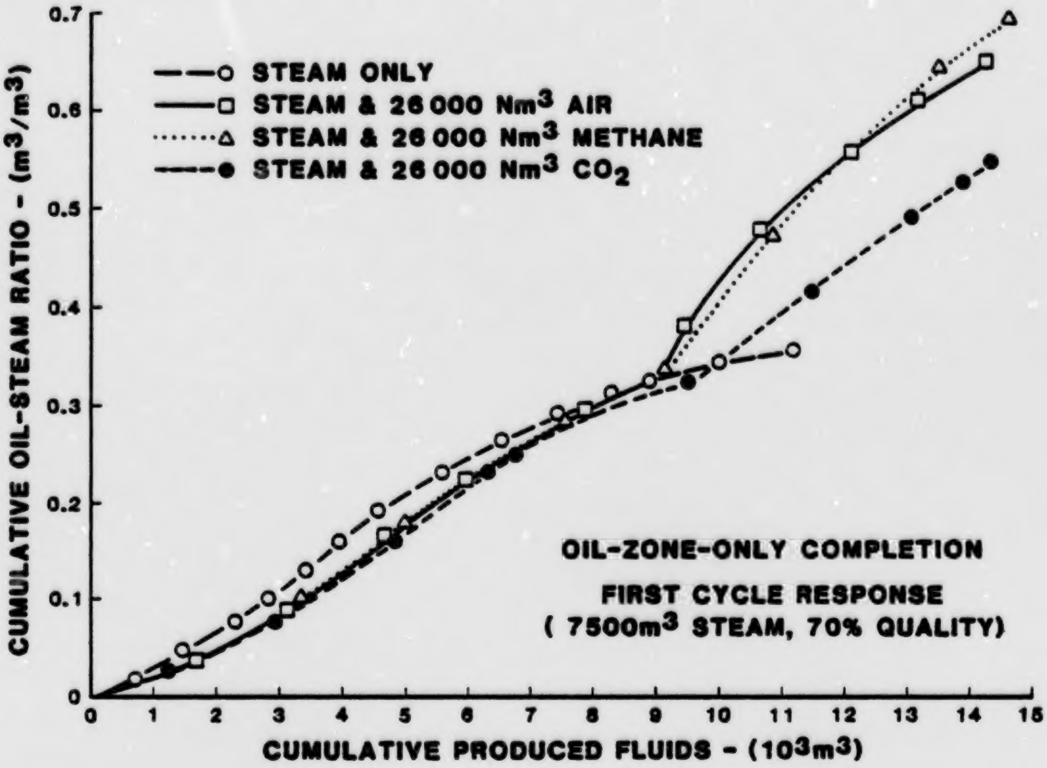

Figure A-1
THE EFFECT OF GAS INJECTION DURING PRODUCTION PHASE OF CYCLE ON ULTIMATE OIL RECOVERY

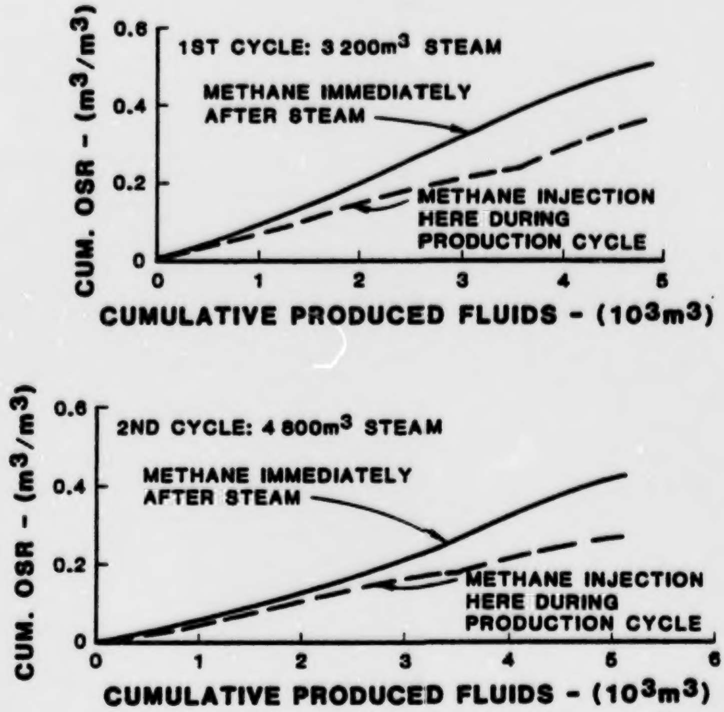

Figure A-2
THE EFFECT OF METHANE INJECTION IMMEDIATELY AFTER STEAM

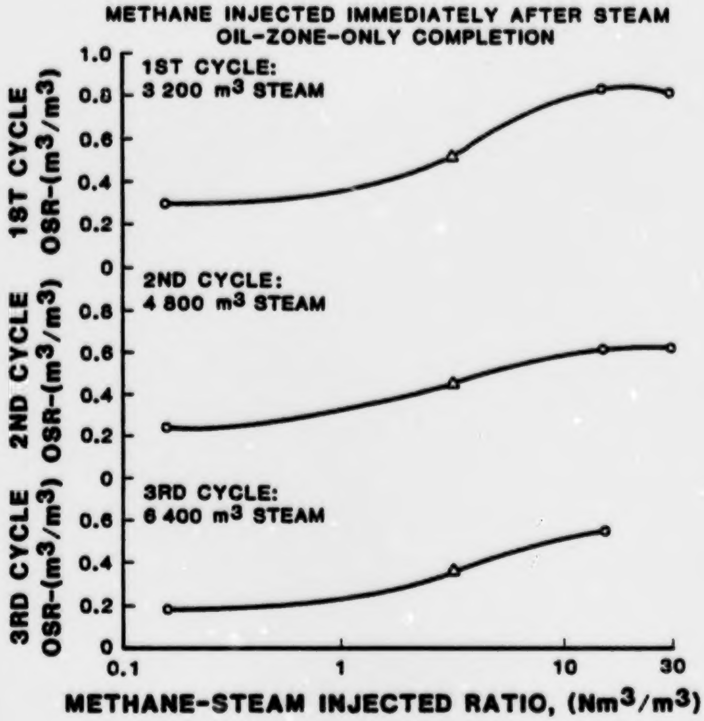

Figure A-3
THE EFFECT OF INCREASING METHANE-STEAM INJECTION RATIO

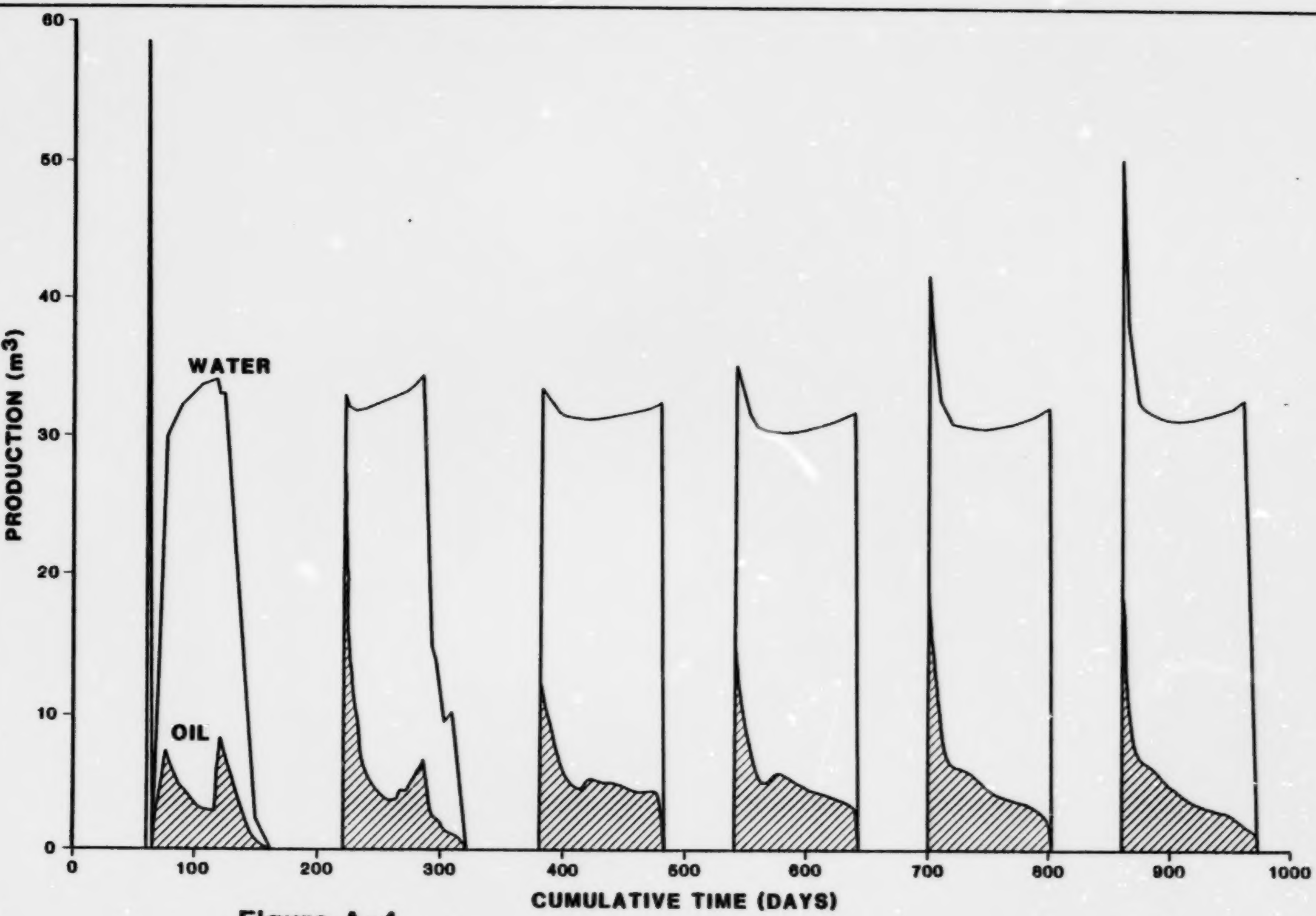

Figure A-4
SINGLE WELL RUN-OIL AND WATER PRODUCTION RATES
FOR EACH CYCLE; GAS INJECTION PRIOR TO STEAM

when 13 000 Nm³ (500 000 scf) of gas were injected after 3600 m³ (22 500 bbl) of steam in each of six cycles. On the whole the author's findings regarding the efficacy of natural gas as additive to steam were somewhat inconclusive. This arises from the uncertainties inherent in the relative permeability data. Indeed, by changing the hysteresis model, the results could be varied enough to render an ostensibly favourable case unfavourable. One effect was quite clear: if gas is injected prior to steam injection, it becomes relatively "easy" to inject steam, because the injected gas provides sufficient relative permeability to steam. In all runs, the gas tended to slow the decline of oil production rate in view of the compressibility imparted to the formation.

AIR INJECTION WITH STEAM

It was noted above that Imperial Oil had some success with air injection with steam, although they noticed spontaneous ignition in the field test. In the Paris Valley steam/combustion test, with which the author has first-hand familiarity, air was injected as an additive to steam. Results of the field test and computer simulations were reported by Meldau et al (Reference A-3). It was found that air nearly doubled oil production from three cycles. Results are summarized in Table A-1, which compares the response for steam only with air/steam injection. It is seen that there was considerable improvement as a result of air injection. Also it was noticed, as noted above, that air injection improved steam injectivity.

It should be added, however, that the above results, though encouraging, are only for three cycles, in a very complex project which started out as a combustion project. The simulations reported showed qualitatively that performance improvement by air was attainable, although not to the

TABLE A-1
RESPONSE TO CYCLIC AIR/STEAM

	Well 20				Well 3	
	Cycle 2	Cycle 3	Cycle 4	Cycle 5	Cycle 6	Cycle 7
Steam volume, m^3	2100	2600	2500	1650	1300	1460
Air volume, Nm^3	0	$39x10^3$	0	$97x10^3$	0	$95x10^3$
Air/steam ratio, Nm^3/m^3	0	15	0	59	0	65
Comparable producing, days	161	161	90*	90	97**	97
Oil produced, m^3	389	747	43	80	377	668
Steam/oil ratio, m^3/m^3	5.4	3.4	58	21	3.5	2.2
Oil/steam ratio, m^3/m^3	0.19	0.29	0.02	0.05	0.29	0.45
Peak production test, m^3/d	8.1	12.9	3.8	6.0	9.5	22.4

*Total cycle: 85 bbl in 142 days for 30:1 steam/oil ratio

**Total cycle: 770 bbl in 270 days for 1.7:1 steam/oil ratio extent observed in the field tests. The reservoir characteristics are quite similar to the Cold Lake formations. No problems with spontaneous ignition were encountered in the field test.

CARBON DIOXIDE INJECTION WITH STEAM

Viscosity

Carbon dioxide (gas) is known to reduce oil viscosity and cause swelling (which leads to an increase in the relative permeability to oil), both of which cause an increase in the mobility of oil. Lately carbon dioxide has received a great deal of attention for miscible flooding of light oils, in the liquid (dense) phase. In the context of heavy oils, carbon dioxide is still in the field-testing stage. In conjunction with steam, carbon dioxide is only now being considered as an additive. Earlier, Klins and Farouq Ali (Reference A-4) showed, based upon a simulation study, that carbon dioxide injected in a waterflood can be effective in increasing oil recovery for moderately viscous oils in the 70-1000 cP range. In relation to heavy oils, the effect of carbon dioxide becomes more complex, partially in view of the lower solubility of carbon dioxide in heavier than in lighter oils. When temperature is also varied, the resulting oil viscosities show a behaviour similar to that in Figure A-5 taken from Bader and Fox (Reference A-5).

It is evident from Figure A-5 that the viscosity of crude oil varies as a function of both temperature and carbon dioxide in solution. The amount of carbon dioxide dissolved in the oil is a function of temperature and pressure. Figure A-5 shows this complex relationship for a typical heavy oil. The curves shown are based upon the relationship:

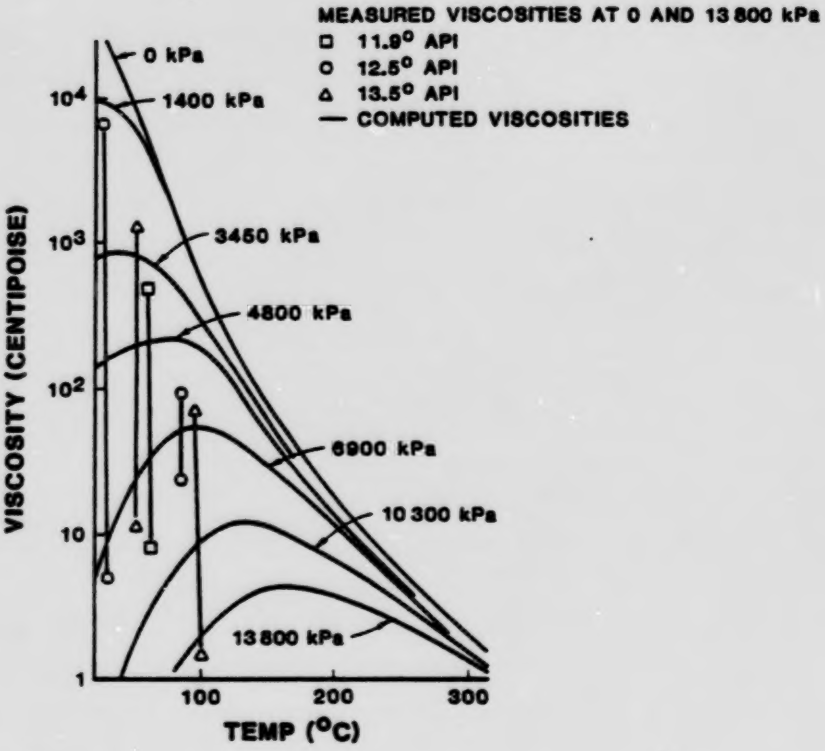

Figure A-5
CRUDE OIL VISCOSITY AS A FUNCTION OF TEMPERATURE AND PRESSURE AT CO_2 EQUILIBRIUM SOLUBILITY

$$\mu_m = (\mu_{oil})^{x_{oil}} (\mu_{CO_2})^{x_{CO_2}}$$

where x_{oil} = mole fraction of oil in the mixture
x_{CO_2} = mole fraction of CO_2 in the mixture

and μ_m, μ_{oil} and μ_{CO_2} are viscosities of the mixture, oil, and carbon dioxide at the prevailing temperature and pressure, with the mole fractions obtained from the relationship

$$K = A\,p\,\exp(B/T),$$

$$\text{where} \quad K = \frac{\text{mole fraction of } CO_2 \text{ in oil}}{\text{mole fraction of } CO_2 \text{ in gas phase}},$$

p is pressure in psia, T is temperature in °R, and typical values of A and B are 1.64×10^{-6} and 3486.63, respectively for the example crude oil (Figure A-5).

The actual measured oil viscosities for three crude oils (API gravities 11.9°, 12.5°, and 13.5°) are superimposed on the theoretical curves based upon the above equations. The upper data point in each case is the measured viscosity at 0 MPa(g) (0 psig), while the lower point represents viscosity of 14 MPa(g) (2000 psig). The data are in fair agreement with the theoretical curves. It is seen that at low temperatures carbon dioxide solubility in oil increases with an increase in pressure, and as a result, oil viscosity decreases. At higher temperatures, carbon dioxide solubility decreases and, even though viscosity drops as temperature increases, the reduced carbon dioxide in solution has a greater effect on viscosity and the viscosity increases. This observation and the data in Figure A-5 are important for gaining an understanding of carbon dioxide - steam injection process. Such data are very difficult to find.

Computer Simulations

Use of carbon dioxide with steam in cyclic steam stimulation has been field tested to a very limited extent so far. Laboratory studies include Pursley's (Reference A-2) work cited previously (Figure A-1). It is possible that Imperial Oil tested this process in Cold Lake. The only means of gaining some insight into the process are numerical simulation studies. In particular, we shall briefly consider the one carried out by Intercomp for Zimpro-AEC (Reference A-6), and another for Sandia Laboratories, which is proprietary information for the greater part. First a critique of the simulations is in order.

The chief shortcoming of the above simulations (cyclic stimulation in particular) is that they do not allow for formation fracturing (or, more correctly, parting and closure) during steam injection at frac pressures and above. As a result, the relative permeability curves have to be modified drastically until they have no resemblance to typical measured curves. Other adjustments include use of a very high rock compressibility factor and initially mobile water. The irreducible water saturation of 20 percent used in the simulation is approximately one-half of the measured values for Cold Lake. The critical gas saturation of 2 percent is also uncertain, yet it has a far-reaching effect on the results. It is recognized that the simulator used does not permit fracturing, and possibly the elaboration of relative permeability and other data was beyond the scope of the studies conducted. Nevertheless these features cast doubt on simulation results. Having carried out thousands of steam injection simulations, the author is aware that it is relatively easy to produce improbable results unless an in-depth study of the variables is conducted.

In the context of carbon dioxide (or other gases), a major problem with simulations is that phase equilibrium is assumed to be instantaneous. In other words, carbon dioxide is assumed to dissolve instantaneously in the oil. This is not necessarily so. In fact, the solution of carbon dioxide in a heavy oil may take days, based upon laboratory data. On the other hand, carbon dioxide does dissolve eventually, even in the semisolid Athabasca bitumen.

Lack of phase equilibrium will profoundly distort the observed simulation results. The carbon dioxide, instead of dispersing evenly in the oil, would tend to migrate toward the top of the formation due to gravity difference, and create a high permeability channel there, for subsequent channeling of both steam and carbon dioxide. In fact, the overall behaviour may be closer to that noted in the section on steam - carbon dioxide - nitrogen injection, where nitrogen plays this type of role rendering the overall process very inefficient compared to steam alone.

It is difficult to numerically simulate non-equilibrium phase conditions. The author has incorporated this effect in one of his steam stimulators using an approximation. Even with that, laboratory data are needed to utilize such a model in an effective manner.

It is not clear whether or not the Intercomp simulations consider carbon dioxide as a separate component from gas, and whether the variable bubble point feature is allowed. Both of these are important.

Cyclic Steam Stimulation Simulations

Intercomp's simulations of cyclic steam stimulation in Cold Lake are detailed in Reference A-6. The data used are typical of Cold Lake in Imperial Oil's leases, and thus represent the "best" formations in Cold Lake deposits. Table A-2, taken from the said reference, summarizes the results of cycle stimulation injecting carbon dioxide with steam. The injection and production times as well as rates are given in Table A-3, the data for which were taken from the discussion in the report.

It is seen that injection of carbon dioxide with steam has the effect of increasing the oil-steam ratio over that attainable by steam alone. In terms of oil production per GJ injected, the improvement using carbon dioxide as compared with steam alone ranges from 30 to 37 percent (dissolved gas and no dissolved gas). Table A-3 shows that the production periods using carbon dioxide are somewhat longer, but this increase is most evident in the first cycle. By the third cycle this effect is not well defined.

It can be concluded that injection of carbon dioxide with steam (as opposed to before or after) helps to increase oil recovery. As to what the actual increase would be is open to question. In the author's opinion, the increases calculated represent upper limits.

Steamflood Simulations

Intercomp carried out a simulation study for Sandia Laboratories for a typical deep California heavy oil formation, using carbon dioxide and flue gas as additives to steam, in a steamflood (steam drive). Most of the results of this study are proprietary. Figure A-6 shows a selection of these for steam alone, steam plus carbon dioxide, and steam plus nitrogen and carbon dioxide. The input data used are:

TABLE A-2
ZIMPRO-AEC LIMITED STEAM ADDITIVE PROCESS
SUMMARY

	Reservoir with dissolved gas		Reservoir with no dissolved gas	
	STEAM	CO_2-STEAM	STEAM	CO_2-STEAM
Total days for 3 cycles	588	650	660	631
CYCLE 1 OSR (m^3/m^3)	0.118	0.152	0.099	0.166
CYCLE 2 OSR (m^3/m^3)	0.156	0.324	0.162	0.309
CYCLE 3 OSR (m^3/m^3)	0.227	0.304	0.206	0.247
Oil Production per calender day	47	64	46	63
Overall WOR (m^3/m^3)	5.02	3.65	4.94	3.56
Overall GOR* (m^3/m^3)	140	1210	0	1215
m^3 Oil Produced/GJ Injected	0.063	0.082	0.058	0.079

* Including CO_2 production

TABLE A-3
INJECTION TIMES AND RATES USED IN CYCLIC STEAM STIMULATION SIMULATIONS IN INTERCOMP'S STUDY

Cycle	Inj. Period days	Steam Inj. Rate m^3/d	CO_2 Inj. Rate Nm^3/d	Soak Time days	Production Time days
No Dissolved Gas					
1	85	190	-	2	166
2	35	190	-	2	118
3	35	190	-	2	161
Dissolved Gas					
1	84	190	-	2	146
2	35	190	-	2	118
3	35		-	2	142
No Dissolved Gas					
1	84	190	$18.6x10^3$	2	189
2	35	190	$18.4x10^3$	2	148
3	35	190	$18.5x10^3$	2	134
Dissolved Gas					
1	84	190	$18.6x10^3$	2	194
2	35	190	$18.5x10^3$	2	133
3	35	190	$18.5x10^3$	2	163

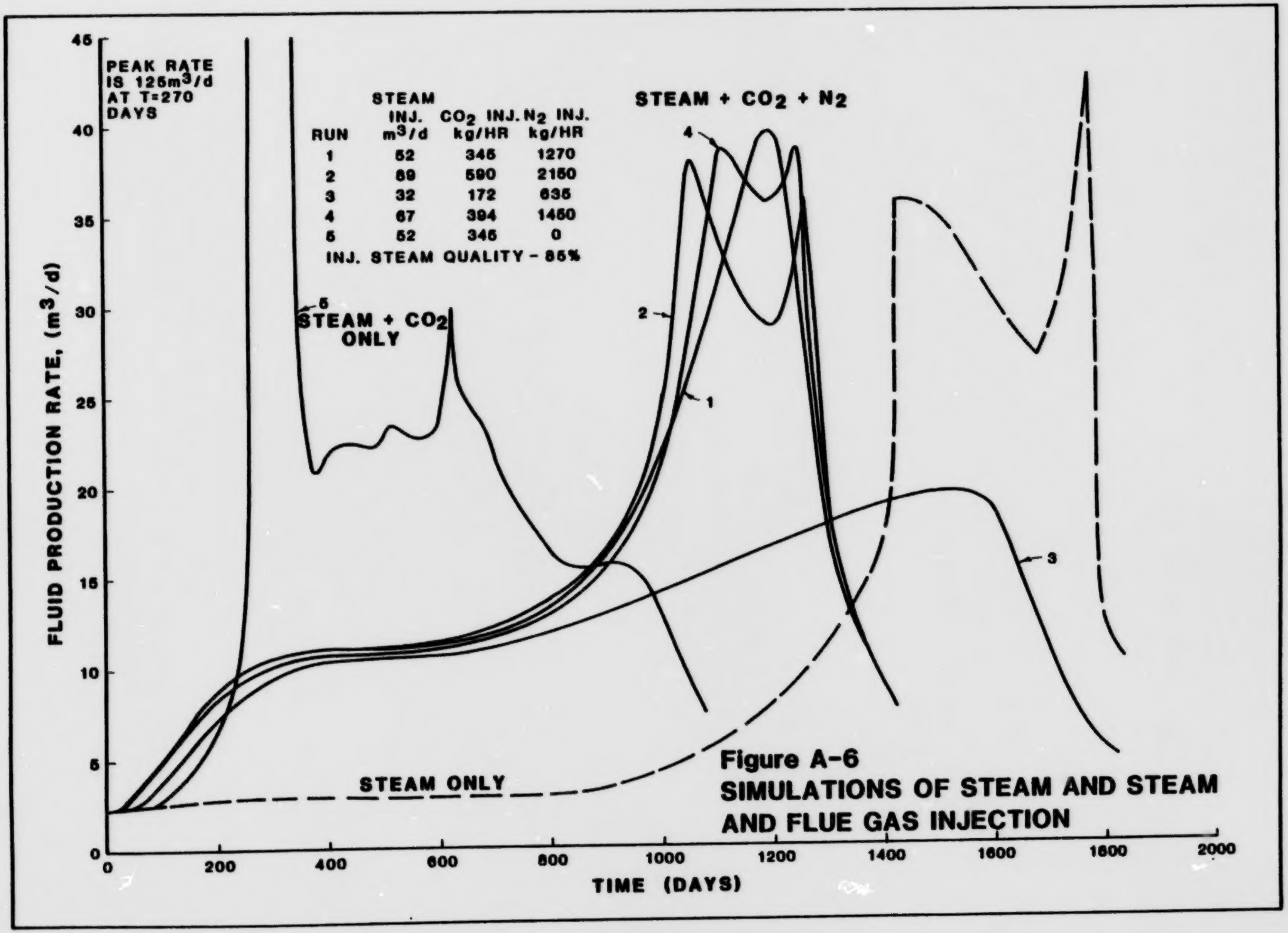

Figure A-6
SIMULATIONS OF STEAM AND STEAM AND FLUE GAS INJECTION

Depth	1280 m (4200 ft.)
Thickness, gross	32 m (105 ft.)
net	22.6 m (74 ft.)
Porosity	28 percent
Permeability, K_h	750 md (0.75 μm^2)
K_v	150 md (0.15 μm^2)
Heterogeneity, V_{DP}	0.7
Initial Temperature:	60°C (140°F)
Initial Pressure	9653 kPa (1400 psi)
Oil Saturation	60 percent
Oil Viscosity	1000 cP at 140°F

A very coarse 35-block grid was used. The limitations discussed in a previous section apply here also. Comparing curve 5 for carbon dioxide with the dashed curve for steam only, it is evident that carbon dioxide led to earlier oil production and improvement in oil recovery. However, the curve appears to be unrealistic in the light of the author's laboratory findings discussed below. Although improvement with carbon dioxide is to be expected; the extent of improvement is open to question.

FLUE GAS INJECTION WITH STEAM

General

The idea of flue gas injection into oil reservoirs is quite old. In the mid-fifties, a series of field tests were conducted in which flue gas was injected into individual wells for stimulation. Most of these attempts were unsuccessful. Currently, the injection of flue gas with steam emanates from several of the novel steam generation technologies discussed in this report, in particular the downhole steam generator. In downhole steam generation, a fuel, such as gas or diesel oil is burned at the sand face in a suitable burner, using air as the oxidant (oxygen could be employed as well). Water is then directly injected into the high-temperature flame, so that the fluid stream entering the sand consists primarily of steam plus nitrogen, carbon dioxide, and oxygen being in the volumetric ratio of approximately 62 steam : 32 nitrogen : 5 carbon dioxide : 1 oxygen. It is clear that there is a large volume of nitrogen along with carbon dioxide. The partial pressure of the latter is low, and therefore the viscosity reduction effect discussed previously is minimal. Laboratory studies by Jacobs et al (Reference A-7) have shown that nitrogen has a negligible effect on oil viscosity.

At the present time, about a dozen manufacturers are in the process of developing and testing downhole steam generators. In most of these, the above cited methodology is employed. A different type of steam generator is the wet air oxidation boiler, where the effluent stream again consists of steam plus flue gas.

We shall briefly consider the field test results using two downhole steam generators and one surface generator, using a similar principle. Following that, we shall review recent laboratory results using flue gas with steam, and finally we shall summarize results of computer simulations of the process.

Downhole Steam Generators

Among a dozen manufacturers in the U.S. and other countries, Corco's downhole steam generator and Carmel's Vapor Therm Surface Generator have been publicized extensively. Sandia Laboratories have been involved in developing a series of downhole generators and auxiliary equipment for several years, under a $26 million contract with the U.S. Department of Energy. They have been field testing two of their generators for some time.

Corco have conducted several short duration well tests using their steam generator, which is fully described in Reference A-8. Field results have been reported in the Oil & Gas Journal and Enhanced Recovery Week from time to time. Generally speaking, based upon field testing in heavy oil fields in California (Kern River: Getty and Tenneco), oil production increases of 100 percent to 900 percent have been claimed. In the author's opinion such figures should be viewed with great caution. First, the tests conducted were of very short durations. Secondly, there seems to have been relatively little control of variables. In any event, the observed responses were for cyclic steam stimulation rather than steamflooding, which is the process for which downhole generators are basically designed. With these limitations in view, it should be noted that for the two cycles reported by Eson (Reference A-9), the downhole steam generator led to oil production rates twice as great as those observed in conventional steam stimulation. It is not known how long such rates could be sustained.

Carmel Energy have developed the Vapor Therm system, in which a mixture of crude and diesel oil is burned with a stoichiometric amount of air in a combustion chamber at a high pressure (up to 10 MPa (1500 psi), producing a hot gas mixture, 1370 to 2200°C (2500 to 4000°F), containing predominantly nitrogen, carbon dioxide, water and trace gases. This mixture is quenched with water to produce steam at 315-400°C (600-750°F) containing nitrogen and carbon dioxide, which is injected into the formation. The system has been described in detail by Sperry (Reference A-10), Williams (Reference A-11), and others. Three field tests have been reported (Reference A-10), showing encouraging response. One of these (Eastburn in Missouri) was expanded and recently visited by project staff. Oil recoveries observed following the expansion failed to live up to early expectations, with total production of 1.2 m^3/h (180 B/d) from 136 wells.

Difficulty in maintaining reservoir pressure has been attributed to channeling through old wells. An alternative explanation is channeling and early breakthrough due to the large volume of nitrogen present.

The wet air oxidation boiler has received considerable attention in recent years, and currently Zimpro-AEC are developing a 15 MW (50 MM Btu/h) unit for a field test in Canada. The wet air oxidation principle has been described in detail by Balog et al (Reference A-12). The important aspect of WAO boiler is that it would produce a mixture of steam, nitrogen, and carbon dioxide much like Carmel's Vapor Therm system, but probably with few pollutants (SO_2 and NO_x), if air is used as the oxidant. With oxygen, only carbon dioxide will be produced with steam. It is thus possible to conjecture that the performance of WAO boiler would be similar to that observed for the previously noted systems, which either produce steam and carbon dioxide or steam, carbon dioxide, and nitrogen.

Sandia Laboratories have developed three downhole steam generators similar to Corco's in concept. One of these was field tested in 1980; a brief description follows. Two others are being tested in Long Beach, California, one utilizing air, the other utilizing oxygen. In the latter tests numerous operational problems have been encountered, which have apparently helped in design improvements.

Sandia's Field Test

Sandia tested their low pressure downhole steam generator in the Kern River field on Chevron's leases. The 2400 kPa(g) (350 psig) generator was run at 1 MW (3.5 MM Btu/hr) output for the first three and one half months. The steam quality during this period averaged 50 percent. Later, the output was increased to 1.5 MW (5 MM Btu/hr). The well pattern is shown in Figure A-7. The three wells indicated showed early breakthrough of the injected steam. In the last month or so, 190 m³ (50 000 gallons) of a foam solution were injected into the sand to block the steamed zone. This was unsuccessful in that there was no effect on production. However, the inner tier of wells did produce some foam. An interesting aspect of the test is the composition of the produced gas. Compositions of the gas at the generator discharge and at the production wells were as follows:

	At Generator	At Producer
Nitrogen	80 percent	80 percent
Carbon dioxide	13 percent	13 percent
Hydrogen sulphide	0	Trace
Carbon monoxide	3 percent	0.5-1.5 percent
Sulphur oxides	5000 mg/L	1 mg/L
Nitrogen oxides	800 mg/L	50 mg/L

It is clear that the oxides of sulphur and nitrogen were significantly reduced during passage through the sand. Corco reports that a similar phenonmena has been observed in their steam stimulation tests (Reference A-13), thus suggesting the desirability of this type of steam generator from an environmental standpoint. It was equally clear in the Sandia tests that the presence of flue gas was not as conducive to oil recovery as the numerical simulations (discussed below) showed. Possibly, nitrogen led to the early breakthrough and channeling.

The field test produced 4000 m³ (25 000 bbl) of oil, at approximately the same oil-steam ratio (about 0.2 m³/m³) as that observed in the neighbouring Chevron steamfloods using conventional steam generators. The overall performance of the field test was not as good though, considering the production distribution among wells, oil rates, etc. There was no emulsion production in spite of foaming solution injection. Also there were no corrosion problems. Rapid gas phase transport of steam was evident throughout.

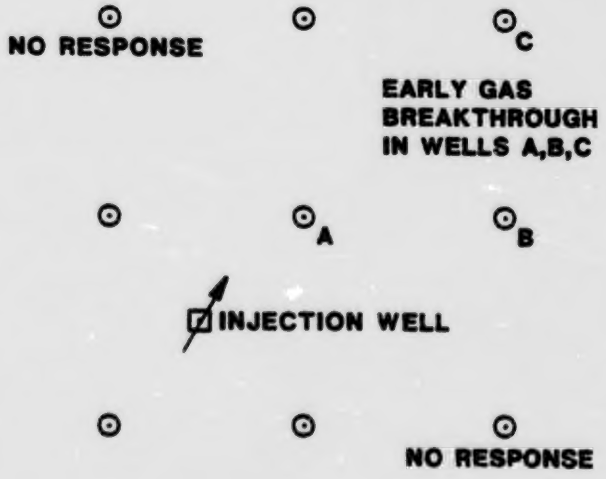
NO RESPONSE
C
EARLY GAS BREAKTHROUGH IN WELLS A,B,C
A
B
INJECTION WELL
NO RESPONSE

Figure A-7
WELL PATTERN USED IN SANDIA'S KERN RIVER FIELD TEST

Laboratory Results

A research project is being conducted under the author's supervision at the University of Alberta, where the intent is to determine the effect of gas injection with steam on oil recovery. Runs are being conducted in a 1.2 m (4 ft) cylindrical sand pack, using a 318 cP oil, using steam alone, steam and carbon dioxide, and steam and flue gas (carbon dioxide and nitrogen). The experimental conditions are kept as constant as practicable, in order to observe the effect of gas injection with steam. Results obtained for the first seven runs are presented in Table A-4. It seems, on the basis of very limited data, that the oil-steam ratio improves somewhat when carbon dioxide or flue gas is injected with steam. More important, the oil production is considerably accelerated due to the presence of a gas.

In a recent publication, Redford (Reference A-14) reported results of injection of steam, as well as steam with naphtha, hydrocarbons, or carbon dioxide, for the recovery of Athabasca bitumen. The experimental set-up was quite complex. However, comparative results are still of value. The experimental procedure was a combination of steamflooding and pressure cycling, using two wells in a cylindrical sand pack. The selected additives, typically carbon dioxide or ethane and naphtha, were injected together with steam. It was concluded that naphtha (Suncor) helped to improve oil recovery through dilution of inplace bitumen, while carbon dioxide or ethane improved the drawdown portion of a cycle by providing a gas drive, which produced cooler fluids from the cooler portions of the sand, thus improving sweep efficiency.

Computer Simulations

Intercomp's numerical simulations for Sandia and Zimpro-AEC, referred to earlier (Reference A-6) also included simulations

TABLE A-4

AVERAGE INITIAL CONDITIONS

pack density, g/cm³	1.55
porosity, percent	42.9
abs. permeability, d	8.7
water sat., % PV	19.9
oil sat., % PV	80.1

EXPERIMENTAL RESULTS

RUN NUMBER	2	3	4	5	6	7
RUN TYPE	STEAM ONLY	SLUG CO_2, LOW QUAL STEAM	STEAM ONLY	SLUG CO_2 STEAM	STEAM, FLUE GAS	STEAM CO_2
Back pressure, kPa(ga)	3342	2250	3364	3350	3323	3404
Steam injection rate, cm³/h	888	1677	1034	1189	1116	1251
CO_2 injection rate, dm³/h	-	283	-	187	106	122
N_2 injection rate, dm³/h	-	-	-	-	418	-
CO_2 - steam ratio, dm³/kg	-	158.3	-	96.2	95.4	98.0
N_2 - steam ratio, dm³/kg	-	-	-	-	373.9	-
Gas-steam ratio, dm³/kg	-	158.3	-	96.2	469.3	-
Oil recovery, percent	79.9	77.9	80.9	89.2	83.3	86.5
Cum. avg. oil-steam ratio, m³/m³	0.226	0.206	0.280	0.260	0.342	0.321
Cum. avg. steam-oil ratio, m³/m³	4.42	4.85	3.57	3.84	2.92	3.12
Cum. avg. water-oil ratio, m³/m³	5.11	4.66	4.09	3.91	2.65	2.87

of steamflooding and steam stimulation, respectively, using flue gas (nitrogen and carbon dioxide) as additive.

In the case of cyclic steam stimulation, with flue gas as additive, it was found that using 20.8 mole percent nitrogen and 5.5 mole percent carbon dioxide with steam, injectivity was greatly reduced, so that is took twice as long as steam alone. Also, because of the lack of solubility of the injected nitrogen in the reservoir oil, a sharp pressure gradient exists at the gas front, with the pressure behind the front essentially equal to the injection pressure. As a result the injection rate is reduced. The production performance was poor, and is shown in Table A-5. It is seen that the oil-steam ratio was 0.05, for the case of dissolved gas, and 0.10 m^3/m^3 for the case of no dissolved gas in the reservoir oil. This is far below 0.15 m^3/m^3 for steam alone.

In the case of steamflooding, apparently the simulations did not show as poor performance as noted above for cyclic stimulation. The results for the Kern River field are summarized in Figure A-6. The dashed curve is for steam alone, while curve 1 represents the approximate proportions of carbon dioxide and nitrogen in the flue gas. The data for the two curves are not quite comparable. In any event, it is clear that injection of flue gas with steam has the effect of recovering the same amount of oil in two-thirds the time.

It should be pointed out that the results shown in Figure A-6 are subjected to the simulation limitations noted previously. In particular, use of proper relative permeability curves is crucial in runs of this type. If the curves are truly representative of the process under consideration, then there is an extremely complex relationship between the relative amounts of steam, carbon dioxide, and nitrogen, as the data listed in Figure A-6 shows.

TABLE A-5
ZIMPRO-AEC LIMITED PROJECT
STEAM ADDITIVE PROCESS
N_2CO_2-STEAM INJECTION CASE

	Reservoir with dissolved gas	Reservoir without dissolved gas
Total steam injection (m^3)	16.2×10^3	16.5×10^3
Total carbon dioxide injection (m^3)	1.48×10^6	1.50×10^6
Total nitrogen injection (m^3)	5.6×10^6	5.7×10^6
Total heat injection (GJ)	47×10^3	48×10^3
Days on injection	100	190
Days shut-in	2	2
Days on production	398	258
Total oil production (m^3)	806	1690
Total water production (m^3)	6600	2900
Total gas produced (m^3)	1.79×10^6	0
Total CO_2 produced (m^3)	0.58×10^6	0.30×10^6
Total N_2 produced (m^3)	3.02×10^6	1.55×10^6
Cycle water oil ratio (WOR)	8.2	1.74
Oil steam ratio (m^3/m^3)	0.05	0.10
m^3 oil produced/GJ injection	0.017	0.035
Production per calender day	10	24

■■ MECHANISMS OPERATING IN STEAM-GAS INJECTION PROCESSES

CYCLIC STEAM STIMULATION

When a noncondensible gas, such as air or nitrogen is injected with steam, an important effect is that the mixture pressure at the same temperature is higher than that of saturated steam. In other words, whereas a vapour such as steam can only have one temperature for any given pressure (if saturated, and below the critical point), a gas-vapour mixture can have *any* combination of pressures and temperatures. This is useful in deep formations, where normally a high pressure but only a moderately high temperature would be needed.

From a mechanistic standpoint, injection of a noncondensible gas would promote (i) increased relative permeability to gas, and (ii) greater tendency to gravity override of steam. The latter can be desirable under special circumstances, but in most cases it would have a deleterious effect on oil recovery. A noncondensible gas saturation would also impart added compressibility to a porous medium, as a result of which, the production phase of a steam stimulation cycle will become prolonged.

When a condensible gas such as carbon dioxide is injected with steam, the mechanism is rather complex. At the steam front, and behind the front, the solubility of carbon dioxide would be low, therefore it would tend to behave somewhat like a noncondensible gas. There would be a tendency for gravity override near the steam front, which would eventually accelerate the natural tendency of steam to migrate toward the top of the formation. Also, carbon dioxide will flow across the steam front and dissolve in the oil farther downstream, where the temperature is low. During the production phase, the carbon dioxide dissolved in the oil would partly come out of solution near the wellbore, and tend to restrict liquid inflow into the well. This may not be serious depending on the amount of carbon dioxide injected. But the presence of a noncondensible gas will aggravate the situation, because the partial pressure of carbon dioxide will be decreased and it would find it increasingly difficult to stay in solution.

STEAMFLOODING

The above cited effects of a noncondensible or condensible gas with steam would also be present in the case of a steamflood, except they will be more pronounced in view of the much longer times involved in steamflooding as compared with cyclic stimulation. In the case of carbon dioxide, an important effect is the solution of carbon dioxide in the cold formation far ahead of the steam front. This provides low level stimulation of the cold oil, thus improving productivity of the producers. On the other hand, if a considerable volume of a noncondensible gas is also present, the gases will come out of solution in the vicinity of the producers and restrict liquid flow.

Possibly a redeeming feature of a noncondensible gas would be the provision of a trapped saturation zone in the oil-bearing formation, effectively lowering the residual oil saturation, something similar to the concept of "prior gas injection" in waterflooding at moderate pressures.

It should be pointed out that in the above cited effects, the critical gas saturation plays a vital role.

It is also notable that the use of a noncondensible gas to "tail off" a steamflood has also been proposed. The idea is to replace the expensive steam by a gas that would still provide the drive, assuming that the temperatures are high enough in any case. At this time there is little experience with this variation of steamflooding. In 1967, Merriam (Reference A-15) proposed using a noncondensible gas (nitrogen) in hot waterflood. Here the intent was to create a gas phase to promote steam distillation of the light oil under test.

EFFECT OF A NONCONDENSIBLE GAS ON STEAM FRONT STABILITY

Although steam is a low viscosity gas, usually displacing a high viscosity oil in a steamflood, effectively it acts as a viscous fluid in view of its condensible nature, and the resulting front is stable, at least at temperatures less than 165°C (330°F). Above 370°C (700°F) the front is unstable. This is easy to see because, being close to the critical temperature, steam behaves as hot water, which is well known to form an unstable displacement front. In a detailed analysis, Krueger (Reference A-16) shows that injection of nitrogen along with steam (nitrogen mole fraction 0.29) makes the system more unstable for steam temperatures between 100° and 195°C (210° and 380°F). From this temperature to the critical there may be a small tendency to stabilization. These findings were qualitatively verified in Hele-Shaw type models. It is conjectured that if only carbon dioxide is injected with steam, then at higher pressures it would have a stabilizing effect.

OVERALL ASSESSMENT

Based upon the above discussion, it seems that use of flue gas with steam is likely to have a greater chance of success in the case of steamflooding than in cyclic steam stimulation. Downhole steam generators, by virtue of their design and cost are really suited for deep steamfloods rather than cyclic stimulations, which is rather fortunate in view of the foregoing.

While the effects of flue gas injection with steam still need to be elucidated by much additional field testing and laboratory studies, it seems that the presence of a gas phase with steam can permit greater flexibility in pressure-temperature selection, promotes greater steam distillation, improves steam injectivity in very viscous oils, and helps to maintain well productivity due to the additional compressibility imparted by the gas. At the same time, a noncondensible gas, such as nitrogen in the flue gas, would increase the tendency to gravity override of steam (which may be undesirable) and restrict liquid phase relative permeability. Then also the producers will have to handle large volumes of gas, with the attendant production and mechanical problems.

In the case of cyclic steam stimulations, the effect of flue gas with steam will be primarily to provide somewhat increased production drive. However, this could be offset by the reduced liquid flow due to large volumes of gas. Other advantages previously noted for carbon dioxide would be present to a limited extent.

On the whole, it is concluded that flue gas (nitrogen and carbon dioxide) is more likely to be effective in a steam-flood type process than in cyclic steam stimulation. This is also generally true for carbon dioxide injection.

USE OF OXYGEN INSTEAD OF AIR IN COMBUSTION

USE OF OXYGEN VERSUS AIR

In-situ combustion usually involves initiation of a firefront in the reservoir formation, and its subsequent propagation by air injection. Oxygen supports combustion and determines the frontal advance rate. Nitrogen is unavoidable and must be compressed along with oxygen. More seriously, it impedes liquid flow, and furthermore causes production well problems, such as erosion, abrasion, gas locking of pumps, environmental pollution, etc. Use of pure oxygen, or oxygen-enriched air has received a great deal of attention in the past decade. A number of oxygen manufacturers (Air Products & Chemicals, Union Carbide, Air Liquide) are actively promoting the use of oxygen in lieu of air. The benefits envisioned for oxygen are primarily the savings in compression cost, and minimization of high gas production problems noted above. With nitrogen absent, the carbon dioxide produced by combustion will dissolve more readily in the inplace oil, thus providing stimulation of the producers to some extent.

The main difficulty with oxygen-driven combustion resides in the fact that very little has been published on the reservoir aspects of oxygen combustion. In 1965, the U.S. Bureau of Mines gave a talk in Pennsylvania where they outlined their laboratory findings concerning oxygen-enriched combustion. On the whole, the study was inconclusive as to oil recovery and benefits of oxygen.

Recently Tejas Engineers in the U.S. as well as ARCO have carried out laboratory studies of oxygen-enriched combustion. The combustion tube at the University of Calgary has been rigged up for such experiments. Moss (of Tejas) and Cady

(Reference A-17) recently reported two laboratory experiments using oxygen in one case, and oxygen-water injection in the other, comparing the results with the same experiments using air. The porous media and oil were taken from Cummings Sand of Lindbergh field, Alberta, where Dome is conducting an oxygen flood. Results show that the peak temperatures using oxygen or air were similar, the fuel deposition was higher using oxygen (e.g., 37 kg/m^3 (2.3 lb/ft^3)) for oxygen vs. 30 kg/m^3 (1.9 lb/ft^3) for air); and only about 68 percent of the injected gas was produced. It was found that the oxygen requirement increased in oxygen combustion as compared to air supported combustion (e.g., 83.5 Nm^3/m^3 (3916 M scf/ac-ft) for oxygen vs. 61 Nm^3/m^3 (2873 scf/ac-ft) for air). Only 70 to 80 percent of the injected oxygen reacted in the high temperature combustion zone. The remainder reacted ahead of the burning front, leading to a higher apparent hydrogen-carbon ratio in the fuel deposited, as compared to air. This increased tendency to low temperature oxidation can lead to increased acid formation, in turn leading to sludge formation and production well plugging. These problems have plagued partially quenched combustion, where air and a high proportion of water are simultaneously injected.

Oil recovery was about the same for both oxygen and air combustion, but oxygen increased the rate of oil recovery.

Laboratory results obtained by ARCO have not been published but are known to be "favourable" from the point of view of field application.

On the basis of limited data, it can be said that oxygen-supported combustion is probably more efficient than conventional combustion. The reduced gas production is a definite plus, but great care is necessary in examining low temperature oxidation ahead of the combustion zone, and its detrimental effects on well productivity.

FIELD TESTING

Several years ago, Texaco conducted a small field test in West Germany using oxygen. Details of this test are unknown, except that it was not successful.

The best known field test is that of Greenwich Oil Corporation at Forest Hill, in Texas, which was started in early 1980 (Reference A-18). Some 9 tonnes (10 tons) of oxygen were injected into a single well, and it was planned to inject into five other injectors, increasing the total to 54 tonnes (60 tons) of oxygen per day, by fall 1981. The formation is 4.6 m (15 ft.) thick, 1460 m (4800 ft.) deep. Porosity is 28 percent and permeability averages 626 md. The inplace oil is 10° API. The 55 producing wells produce 2.6 m^3/h (400 B/d). In 1982 May, Greenwich decided to suspend oxygen injection and switched to water to take advantage of the residual heat in the formation. At least from the known data it does not appear that oxygen injection made any particular impact on oil recovery.

Currently, at least three field tests are in the planning stages: Husky Oil's in Waseca Sand, Llyodminster, ARCO's in Texas, and Dome's at Lindbergh, Alberta.

If oxygen-enriched combustion, especiallty in combination with water injection, can be shown to be successful even to the extent of conventional combustion, both technically and economically, it could be the best recovery method for many of the thin oil reservoirs of Saskatchewan.

POSSIBLE APPLICATIONS OF SOLVENT-STEAM AND FLUE GAS-STEAM INJECTION PROCESSES IN WESTERN CANADA

SOLVENT-STEAM INJECTION

The author has been involved in research on solvent-steam injection processes for the recovery of heavy oils and the Athabasca bitumen since 1968. The basic idea is to inject a small amount of a suitable solvent simultaneously with steam, or in any sequence with steam. The solvent primarily serves to create a channel for subsequent steam flow. It can also provide stimulation in the vicinity of the producing wells. Once steam injection is initiated, some strategy must be employed for keeping the initial channel open. The objective in such a process is to minimize solvent requirement for a given oil recovery.

The earlier work by the author and his coworkers utilized pure compounds as solvents. In later work, the Suncor synthetic crude, currently being produced by surface mining and upgrading operations, was employed as the solvent. Apart from miscibility, this crude is basically an aromatic naphtha, as a result of which there are no asphaltene precipitation problems.

Results of one of the recent studies were reported by Farouq Ali et al (Reference A-19). In this work, an Athabasca oil sand pack 380 mm (15 inch) X 380 mm (15 inch) X 250 mm (10 inch) was employed with appropriate confinement and heat loss simulation. Five different steam-solvent injection strategies were employed as described at the end of Table A-6, which summarizes the results of 37 runs. It was found that injection of the solvent into the production wells only for channel development all the way to the injector, or splitting the solvent between the injector and producer were the better strategies.

TABLE A-6 SUMMARY OF EXPERIMENTAL RESULTS

Run No.	Method	Pore Volume (cc)	Slug Size (% PV)	Porosity (%)	Bitumen in Place (cc)	Solvent Injected (cc)	Solvent Injection Time (hr)	Time to Effluent BT (hr)
1	A[a]	14,197	28	41.5	9,217	4,000	6.57	0.88
2	B[b]	13,110	11	38.3	9,979	1,500	12.72	1.63
3	A[a]	11,651	15	34.0	8,118	1,750	5.25	3.23
4	B[b]	11,398	15	33.0	8,390	1,700	3.58	3.58
5	C[c]	12,156	18	35.5	9,084	2,200	3.37	1.53
6	D[d]	12,457	10	36.4	9,333	1,240	1.65	0.13
7	A[a]	12,566	5	36.7	10,394	640	0.88	0.13
8	B[b]	12,330	5	36.1	10,735	620	0.77	0.37
9	C[c]	11,497	5	33.6	10,709	580	0.93	0.05
10	A[a]	11,340	30	33.0	11,158	3.420	6.38	0.13
11	B[b]	11,511	30	33.7	10,958	3,460	10.30	0.22
12	C[c]	11,526	30	33.7	11,317	3,460	6.60	0.13
13	C[c]	11,930	11	35.0	10,919	1,312	1.93	0.18

Run No.	Solvent[e,f] Injected to BT (cc)	Steam[g] Injected (cc)	Time to[h] Steam BT (hr)	Average[i] Injection Rate (cc/min.)	Average[i] Injection Pressure (psig)	Solvent-Bitumen Ratio (vol/vol)	Water-Bitumen Ratio (vol/vol)	Bitumen Recovery (% OBIP)	Solvent Recovery (% Tot.Inj.)
1	740	2,013	0.75	9.4/35.4	3.4/64	3.2	2.88	13.57	75.1
2	240	6,560	5.77	2.0/10.2	71.0/55	0.71	3.17	21.3	76.3
3	1,280	1,945	0.8	5.6/34.7	38.0/150	1.80	4.11	12.0	29.5
4	1,700	19,825	36.53	7.8/8.3	140.0/58	0.41	4.02	49.9	99.8
5	900	16,645	28.27	9.0/9.1	110.0/75	0.56	3.62	43.01	99.5
6	134	6,801	2.1/0.6[h]	12.6/12.8	75.0/60	0.59	2.89	22.3	74.7
7	200	4,910	4.13	12.6/13.2	56.7/35	0.59	5.72	10.5	99.73
8	160	5,607	7.32	12.9/11.3	189.0/34	0.4	3.59	14.5	82.8
9	110	10,433	10.98	10.6/9.5	121.0/38	0.37	6.13	14.8	91.4
10	200	8,947	6.67	8.8/11.2	43.0/38	1.83	4.33	16.73	99.7
11	230	4,238	2.9	5.9/15.1	49.4/36	2.51	2.98	12.6	98.9
12	150	4,350	3.82	8.8/17.8	35.0/37	2.85	3.59	10.73	99.1
13	200	4,839	3.25	11.4/13.8	50.0/35	0.88	2.98	14.01	88.11

Run No.	Method	Pore Volume (cc)	Slug Size (% PV)	Porosity (%)	Bitumen in Place (cc)	Solvent Injected (cc)	Solvent Injection Time (hr)	Time to Effluent BT (hr)
14	SI[e]	11,836.89	-	34.6	9,339.56	-	-	-
15	SI[e]	11,094.67	-	32.4	8,669.86	-	-	-
16	B[b]	11,457.7	20	33.5	9,656.0	2,317	4.65	0.33
17	C[c]	13,781.5	14	40.3	10,618.1	1,939	3.70	0.10
18	C[c]	12,433.9	23	36.3	11,803.85	2,871	5.59	0.67
19	D[d]	11,462.99	5	33.5	8,901.57	580	1.23	0.42
20	D[d]	11,630.90	2.5	34.0	9,715.77	297.5	0.52	0.17
21	B[b]	11,356.27	10	33.2	9,834.74	1,270	2.86	0.66
22	B[b]	11,720.48	10	34.2	10,193.1	1,181	1.35	0.44
23	B[b]	12,079.58	15	37.2	9,523.34	1,818	6.05	0.32
24	B[b]	11,993.37	15	35.0	10,179.98	1,800	2.03	1.30
25	B[b]	12,926.88	15	37.8	11,697.07	2,028	0.99	0.32

Run No.	Solvent[f] Injected to BT (cc)	Steam[g] Injected (cc)	Time to[h] Steam BT (hr)	Average[i] Injection Rate (cc/min.)	Average[i] Injection Pressure (psig)	Solvent-Bitumen Ratio (vol/vol)	Water-Bitumen Ratio (vol/vol)	Bitumen Recovery (% OBIP)	Solvent Recovery (% Tot.Inj.)
14	-	5,389	7.43	-/10.05	-/50	-	5.21	12.06	-
15	-	4,314	3.8	-/12.43	-/165	-	10.07	10.47	-
16	142	7,224.2	6.75	8.305/9.38	260/33	0.94	3.00	24.20	94.52
17	58	4,693	1.85	8.73/32.37	40/41	0.98	4.91	10.92	58.55
18	338	8,411	4.47	8.56/14.16	110/45	0.94	2.79	22.78	88.14
19	196	5,115	8.3	7.86/9.22	65/50	0.30	1.39	21.42	97.23
20	95	5,094.5	4.77	9.6/12.13	60/82	0.21	12.04	5.65	38.52
21	314	10,679	20.05	7.4/7.9	120/60	0.48	3.73	26.38	97.99
22	385	8,502	2.0	14.58/13.56	250/55	0.31	4.83	17.91	47.35
23	92.5	9,942	15.42	5.01/8.86	55/35	0.98	5.64	19.05	97.90
24	1,160.44	10.647	23.55	14.75/6.59	450/50	0.67	5.30	20.18	76.73
25	623	3,227	2.93	34.04/12.18	160/50	0.53	3.33	13.29	40.44

TABLE A-6 Continued

Run No.	Method	Pore Volume (cc)	Slug Size (% PV)	Porosity (%)	Bitumen in Place (cc)	Solvent Injected (cc)	Solvent Injection Time (hr)	Time to Effluent BT (hr)
26	B[b]	13,166	15	38.5	12,486	1,980	3.67	0.42
27	B[b]	11,766	15	34.4	11,541	1,791	3.27	0.83
28	B[b]	12,524	15	36.6	11,358	1,879	3.48	3.48
29	E[e]	12,501	12	36.6	11,652	1,501	3.20	0
30	E[e]	12,890	15	37.9	12,507	1,934	4.13	0
31	E[e]	11,923	15	34.9	10,857	1,788	3.82	0
32	E[e]	12,044	20	35.2	10,702	2,409	5.15	0
33	E[e]	12,345	30	36.1	10,398	3,703	7.91	0
34	B[b]	12,175	15	36.6	10,962	1,826	3.90	2.33
35	E[e]	12,359	40	36.1	10,724	4.944	10.56	0
36	E[e]	12,758	15	37.3	11,464	1,914	2.16	0
37	E[e]	12,407	15	36.3	10,833	1,861	0.91	0

Run No.	Solvent[f] Injected to BT (cc)	Steam[g] Injected (cc)	Time to[h] Steam BT (hr)	Average[i] Injection Rate (cc/min.)	Average[i] Injection Pressure (psig)	Solvent-Bitumen Ratio (vol/vol)	Water-Bitumen Ratio (vol/vol)	Bitumen Recovery (% OBIP)	Solvent Recovery (% Tot.Inj.)
26	219	3,852	0.87	9.0/36.00	30.4/174	1.06	3.03	10.88	72.6
27	468	6,269	3.10	9.0/30.43	228/155	0.70	3.36	16.40	73.9
28	1,879	9,913	15.30	9.0/10.03	260/60	0.63	3.36	23.99	94.3
29	0	10,699	15.05	7.8/11.14	151/56	1.27	9.05	10.10	99.7
30	0	12,305	15.18	7.8/12.80	138/60	0.95	7.07	13.59	83.6
31	0	10,634	17.50	7.8/9.50	135/70	0.70	5.67	17.18	73.2
32	0	9,984	14.32	7.8/11.08	149/72	0.82	3.96	21.60	78.3
33	0	10,825	15.87	7.8/10.34	83.8/75	0.91	5.98	26.18	67.2
34	1,161	13,435	20.95	7.8/10.62	186/61	0.91	7.75	15.47	84.4
35	0	17,184	32.25	7.8/8.68	159/60	1.17	4.30	33.60	85.4
36	0	11,890	16.58	14.8/11.58	142/70	0.78	5.28	19.04	89.0
37	0	14,203	22.33	34.0/10.45	206/68	0.64	5.24	23.29	86.8

NOTES

[a] The whole slug injected into the injection well.

[b] The whole slug injected into the production wells.

[c] Half of the slug injected into the injection well and the other half into the production wells.

[d] Solvent injection alternated with steam (solv. inj. through the injection well).

[e] Solvent slug divided into four slugs; each injected into the production wells at equal intervals.

[f] When this volume is equal to solvent injected, breakthrough occurred on steam injection.

[g] As water.

[h] First figure is for the first steam injection, second figure is for the second injection.

[i] First figure is for solvent, second figure is for steam as water.

[j] No solvent was injected.

Bitumen recoveries in excess of 40 percent of initial bitumen in place were obtained, but required solvent slugs of 15 percent pore volume, in addition to steam.

Current effort is underway on theoretical modelling of thermal-miscible displacement and channel development by solution and leaching.

Other laboratory work using solvents, hydrocarbons/carbon dioxide and steam was reported in Reference A-14, and mentioned previously in this chapter.

FIELD TESTING OF SOLVENT INJECTION

A few very small tests utilizing solvents with steam have been carried out in western Canada, and none of these has been reported in the published literature. Gulf Canada tested this process in Wabasca, with no success. Texaco are currently testing it in the Athabasca sand, near Fort McMurray, and have been partially successful. In both cases the Suncor synthetic crude was employed as the solvents, as proposed by the author in several past publications.

POSSIBLE APPLICATIONS IN WESTERN CANADA

Solvent injection is a very costly proposition, and could be justified only if the expected recovery increase is large enough to offset the cost, or if the solvent is successful in creating an initial channel in an otherwise impervious formation (due to very high oil viscosity). Other methods proposed and being tested for this purpose include fracturing and electrical heating. At this stage there is very little field data, and limited laboratory results based on unscaled models to determine whether solvent injection with steam is likely to be an effective means of enhancing oil recovery by steam injection.

In order to speculate on the use of solvents or flue gas with steam in oil reservoirs in western Canada, it is instructive to consider some of the unique features of these reservoirs. The formations in Saskatchewan are usually very thin, on the order of 3 m (10 ft.) in thickness. They are often underlain by water-bearing sands. Oil viscosity ranges from about 400 to 4000 cP. The oil sands in Cold Lake area are relatively thick, over 15 m (50 ft.), but the oil viscosity is about 50 000 cP. The oil sands in Athabasca are quite thick, but the bitumen viscosity is several million cP. In addition, in Alberta there are several moderately viscous oil reservoirs, with oil viscosities in the range of 100 cP, and underlain by water-bearing sands (e.g., Suffield, Hughenden, David, and several other small fields). The reservoirs in Saskatchewan are generally unsuitable for steam injection because heat losses would be prohibitive. On the other hand, if flue gas can localize steam injection near the formation top, it may be possible to conduct a downward steam drive. Normally thicker formations bearing similar oils would be better candidates for such a process.

In the case of Cold Lake, possibly carbon dioxide injection prior to steam may have a better chance for eventually permitting a steamflood to be conducted, without formation parting. The latter is a more or less necessary evil in current cyclic steam stimulation work in Cold Lake. It is likely that flue gas injection would be less effective, simply because in very high oil viscosity formation the flue gas (mostly noncondensible nitrogen) would lead to very high pressure requirements. Carbon dioxide, on the other hand, would tend to provide prestimulation of the formation.

Such a process may be applicable to the Athabasca oil sands, but the amount of carbon dioxide for prestimulation needed would be excessive. Possibly solvents offer a slightly better choice, if applied judiciously to the formation.

In the opinion of the author, partially quenched combustion, using air and water (about 0.006 m^3 of water per Nm^3 of air (1000 bbl water per MM scf air)), has the best chance of success in the poorer Saskatchewan formations. However, successful application of this process would require a great deal of background research. A crucial aspect of this process are the rock-fluid interactions in the light of the low temperature oxidation kinetics.

RESEARCH NEEDED

In the light of the previous discussion it is clear that (i) very little experimental research has been conducted on steam/carbon dioxide/flue gas injection, and that too in unscaled models. Scaling laws for such studies are yet to be derived; (ii) computer simulations of such processes are very inadequate; in fact, it is difficult to simulate just plain steam injection in either stimulation or flood mode. The greatest uncertainty resides in formation parting, and relative permeability data; (iii) experimental research on partially quenched combustion, a very promising process for thin oil-bearing formation, is almost nonexistent; (iv) much basic rock-fluid data on flue gas systems needs to be obtained. For example, no data is available on the rate of diffusion of carbon dioxide into oil, or on the solubility of nitrogen in oil.

It is clear that the research effort in Canada on the above topics is marginal. (This is also true of other areas of petroleum production research.) Currently, some work on fluid properties is being supported by AOSTRA, but it would be years before it is complete, and in any case, it is proprietary. The Petroleum Recovery Institute has conducted some research on additives, but much of their recent work has been devoted to high concentration sulphur dioxide systems, highly unlikely to be employed in steam injection. Apparently nothing is being done at the University of Calgary on the above topics at the moment. Some effort is underway on the development of a downhole steam generator, but it is mostly related to hardware. At the University of Alberta the author is supervising some work on flue gas-steam injection, in linear sand packs. Computer simulations of such experiments is part of the research. It is intended to establish a scaled physical model facility if and when funding becomes available. Alberta Research Council are carrying out rather complex displacement studies in their large model. The model is unscaled, the runs take months apiece, and the injection-production system is too complex to make generalizations.

In the specific area of flue gas-steam injection, it is suggested that a scaled or semi-scaled model be constructed and facilities be provided to carry out floods of this type for a wide range of conditions to simulate Cold Lake and Lloydminster type reservoirs. Concurrently, additional runs should be conducted in a controlled linear model to observe the mechanistic features of gravity segregation and interphase transfer.

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APPENDIX B

COST ESTIMATING PROCEDURES AND ASSUMPTIONS

APPENDIX B
COST ESTIMATING PROCEDURES AND ASSUMPTIONS

INTRODUCTION

Chapter 4 summarized the costs of steam generation for each of fourteen cases investigated in this study. While general assumptions pertaining to the cost estimating procedure were outlined in Chapter 4, several process-specific assumptions were also required. These are presented in this section of the report with an explanation of the procedures used in deriving the specific capital and operating cost components and a discussion of the key factors affecting the cost of each process.

STEAM GENERATION COSTS

Conventional Once-Through Steam Generators

A. Basis for Cost Estimate

The steam generating plant considered in the cost estimate consists of one unit rated at 158 GJ/h (150 MM BTU/hr) and two units rated at 53 GJ/h (50 MM BTU/hr). The single large unit has been the largest built to date and could be shop fabricated with final assembly in the field. The two smaller units have been the most common standard size used for many heavy oil thermal projects.

Two 50 percent capacity boiler feedwater (BFW) pumps have been provided for all three steam generators. These units could be of various designs and types however, high pressure plunger pumps with electric motor drivers have been included. All major equipment would be installed at a central plant facility.

Firing crude bitumen would require some additional equipment to store, pump, and heat the fuel. In addition, a large flue-gas stack has been provided in the costs because of the sulphur contained in the crude bitumen fuel. Discharging the combustion gases along with the associated SO_2 would likely require a stack of at least 60 - 70 m (200 - 230 ft) in height in order to meet the ground level concentrations outlined by Alberta Environment. Stack-gas scrubbing facilities have not been provided for the crude fired case.

It has been estimated the steam generator thermal efficiency would be approximately 87 percent. There may be slight differences between gas or crude fired cases but it has been assumed the efficiencies would be equal. The product steam for injection would be 80 percent quality.

B. Capital Costs

1.	One 158 GJ/h steam generator package	$1 300 000
2.	Two 53 GJ/h steam generator packages	900 000
3.	Related equipment and installation	1 996 000
		$4 196 000
4.	BFW pumps (2 units)	$ 405 000
5.	Related equipment and installation	344 000
		$ 749 000
6.	Fuel facilities; crude-fired case	$ 120 000
7.	Miscellaneous; crude-fired case, flue gas stack	$ 80 000
	Sub-total: Gas-fired	$4 945 000
	Crude-fired	$5 145 000
8.	Contingency: Gas-fired	$ 989 000
	Crude-fired	$1 029 000
	TOTAL: Gas-fired	$5 934 000
	Crude-fired	$6 174 000

C. Operating Costs; Natural Gas Fired Case

1. Fuel

Consumption:

$$\frac{264\ \text{GJ/h} \times 24\ \text{h/d} \times 330\ \text{d/yr}}{37.257\ \text{MJ/m}^3 \times 0.87} = 64.50 \times 10^6\ \text{m}^3\text{/yr}$$

Cost:

$$\frac{264\ \text{GJ/h} \times 24\ \text{h/d} \times 330\ \text{d/yr} \times \$2.37\text{/GJ}}{0.87} = \$5\ 696\ 000\text{/yr}$$

2. Maintenance

Equipment base cost:	$2 645 000 @ 3 percent	$ 80 000/yr
Auxiliary base cost:	$1 185 000 @ 2 percent	24 000/yr
		$ 104 000/yr

3. Electrical Power

Total load = 870 KVA

Demand charge:
870 KVA X $2.30/KVA X 12 months = $ 24 000/yr

Energy Charge:
870 KVA X 24 h/d X 330 d/yr X $.0125/kW-hr = 86 000/yr

$ 110 000/yr

4. Operators

3 shifts/d	3
1 swing	1
1 supervisor	1
	5 Operators

Cost = 5 X $135/d X 365 d/yr = $ 246 000/yr

5.	Miscellaneous	$ 75 000/yr
	Sub-Total	$6 225 000/yr
6.	Contingency @ 10 percent	$ 622 000/yr
	TOTAL	$6 847 000/yr

D. Operating Costs; Crude-Fired Case

1.	Fuel	
	Consumption:	
	$\frac{264 \text{ GJ/h X } 24 \text{ h/d X } 330 \text{ d/yr}}{44.889 \text{ MJ/kg X } .87 \text{ X } 970 \text{ kg/m}^3}$	$55\ 200\ \text{m}^3\text{/yr}$
	Cost:	
	$55\ 200\ \text{m}^3 \text{ X } \$188.68/\text{m}^3 =$	$ 10 415/yr
2.	Maintenance	
	Equipment base cost: $2 645 000 @ 3 percent	$ 80 000/yr
	Auxiliary base cost: $1 250 000 @ 2 percent	25 000/yr
		$ 105 000/yr
3.	Electrical Power	
	Total load =	910 KVA
	Demand charge: 910 KVA X $2.30/KVA X 12 months =	$ 25 000/yr
	Energy Charge: 910 KVA X 24 h/d X 330 d/yr X $.0125/kW-hr =	90 000/yr
		$ 115 000/yr
4.	Operators	
	3 shifts/d	3
	1 swing	1
	1 supervisor	1
		5 Operators
	Cost = 5 X $135/d X 365 d/yr =	$ 246 000/yr
5.	Miscellaneous	$ 75 000/yr
	Sub-Total	$10 956 000/yr
6.	Contingency @ 10 percent	$ 1 095 000/yr
	TOTAL	$12 051 000/yr

E. Discussion

To date the conventional oil-field steam generators have been fired on gaseous or liquid fuels. The units could fire most gaseous fuels ranging from propane to low BTU waste gases and most liquid from gasoline to heavy bitumen. However, the development of solid-fuel firing has been slow and there do not appear to be any major technological breakthroughs in the near future.

On a very large thermal-recovery project, the conventional steam generators may be fired on low-grade waste gases that may be associated with a bitumen upgrading facility. Also associated with most heavy oil thermal projects could be significant volumes of produced gases and well head annulus vent gases. These gases have generally been of low and variable quality. On a large project a combination of the waste gas streams may be consistent enough to warrant use as fuel in the steam generators. To date on pilot projects these gases have been flared or vented to the atmosphere. There are now plans to run field tests on these waste gases as fuel. Although these systems have promise as a practical fuel supply it is not likely that low-grade gas fuels would be of sufficient volume to support the entire steam load of the project. Make-up or balancing fuel supplies would be required. This could result in more than one type of steam generation facility at a large operation.

The design and construction of conventional steam generators has been directed towards shop-fabricated packages which could be relocated in the field with a minimum amount of field labour. The largest built to date have been the 158 GJ/h (150 MM BTU/hr) units and it is considered likely that multiples of these units would be employed to achieve capacities in excess of 264 GJ/h (250 MM

BTU/hr). Therefore, it is felt that economy of scale would not be significant in this case other than costs related to some of the auxiliary equipment.

Thermosludge Steam Generators

A. Basis for Cost Estimate

The steam generating plant considered in the cost estimate consists of ten units rated at 27 GJ/h (25 MM BTU/hr). This has been the most common standard size used for heavy oil thermal projects. All major equipment would be installed at a central plant facility.

As discussed for the crude-fired conventional once-through steam generators, the firing of crude bitumen would require additional equipment to store, pump, and heat the fuel together with a flue gas stack of at least 60 - 70 m (200 - 230 ft) in height.

It has been estimated the Thermosludge generator efficiency would be approximately 77 percent. There may be slight differences between gas or crude fired cases but it has been assumed the efficiencies would be equal. The steam for injection would be 100 percent quality.

B. Capital Costs

1.	Ten 27 GJ/h Thermosludge generators, related equipment and installation		$12 100 000
2.	Fuel facilities; crude-fired case		120 000
3.	Miscellaneous; crude-fired case, flue gas stack		80 000
	Sub-total:	Gas-fired	$12 100 000
		Crude-fired	$12 300 000
4.	Contingency:	Gas-fired	$ 2 420 000
		Crude-fired	$ 2 460 000

TOTAL: Gas-fired $14 520 000
Crude-fired $14 760 000

C. Operating Costs; Natural Gas Fired Case

1. Fuel

Consumption:

$$\frac{264\ \text{GJ/h} \times 24\ \text{h/d} \times 330\ \text{d/yr}}{37.257\ \text{MJ/m}^3 \times 0.77} = 72.9 \times 10^6\ \text{m}^3\text{/yr}$$

Cost:

$$\frac{264\ \text{GJ/h} \times 24\ \text{h/d} \times 330\ \text{d/yr} \times \$2.37\text{/GJ}}{0.77} = \$6\ 435\ 500\text{/yr}$$

2. Maintenance

Equipment base cost: $14 520 000 @ 3 percent $ 435 000/yr

3. Electrical Power

Total load = 870 KVA

Demand charge:
870 KVA X $2.30/KVA X 12 months = $ 24 000/yr

Energy Charge:
870 KVA X 24 h/d X 330 d/yr X $.0125/kW-hr = 86 000/yr

$ 110 000/yr

4. Operators

3 shifts/d	3
1 swing	1
1 supervisor	1
	5 Operators

Cost = 5 X $135/d X 365 d/yr = $ 245 000/yr

5. Miscellaneous $ 125 000/yr

Sub-Total $7 350 000/yr

6. Contingency @ 10 percent $ 735 000/yr

TOTAL $8 085 000/yr

D. Operating Costs; Crude-Fired Case

1. Fuel

Consumption:

$$\frac{264\ \text{GJ/h} \times 24\ \text{h/d} \times 330\ \text{d/yr}}{44.889\ \text{MJ/kg} \times 0.77 \times 970\ \text{kg/m}^3} = \$\ 62\ 365\ \text{m}^3\text{/yr}$$

Cost:

262 365 m^3 X \$188.68/m^3 = \$11 765 000/yr

2. Maintenance

Equipment base cost: \$14 760 000 @ 3 percent \$ 445 000/yr

3. Electrical Power

Total load = 910 KVA

Demand charge:
910 KVA X \$2.30/KVA X 12 months = \$ 25 000/yr

Energy Charge:
910 KVA X 24 h/d X 330 d/yr X \$.0125/kW-hr= 90 000/yr

\$ 115 000/yr

4. Operators

3 shifts/d 3
1 swing 1
1 supervisor 1

5 Operators

Cost - 5 X \$135/d X 365 d/yr = \$ 245 000/yr

5. Miscellaneous \$ 125 000/yr

Sub-Total \$12 695 000/yr

6. Contingency @ 10 percent \$ 1 269 500/yr

TOTAL \$13 965 000/yr

E. Discussion

To date Thermosludge generators have been fired on gaseous or liquid fuels. Like the conventional once-through generator, the units could fire most gaseous fuels ranging from propane to low BTU waste gases and most liquid fuels from gasoline to heavy bitumen. To date development of solid fuel firing capability in the Thermosludge generator has not yet taken place.

Multi-Solids Fluidized Bed Combustor

A. Basis for Cost Estimate

The steam generating plant considered in the cost estimate consists of a single unit rated at 264 GJ/h (250 MM BTU/hr). A unit of this size has not been built to date but this is the projected size for large thermal projects. A 53 GJ/h (50 MM BTU/hr) plant has been built and operated and the supplier feels the unit could be readily scaled up with no major design or fabrication problems. Large or small, these units require significant field erection work.

Coke and coal would be the primary fuel cases and each has been provided with facilities for limestone addition for SO_2 capture. In the case of the coke-fired generator, the literature indicates that much larger quantities of limestone would be required to achieve the same SO_2 capture efficiency with this high sulphur fuel. This results in much larger volumes of ash for waste disposal. Therefore, additional capital costs have been included with the fuel (solids) handling facilities for the coke fired case.

It has been assumed that for the coal-fired case, where the ash quantities would be smaller, the ash could be hauled by truck to a local landfill site for disposal. However, for the coke-fired case, where the ash quantities would be much larger, it has been assumed the ash would be loaded back onto rail cars, hauled a greater distance for disposal in a mine or reclamation pit.

Steam would be generated at 14 MPa (2000 psi), 335°C (635°F), and 80 percent quality. The steam generator efficiency used in the cost estimate was 78 percent. Although there may be some difference in efficiency between the coal and coke fired cases, 78 percent was used throughout.

B. Capital Costs

1. Steam generator	
264 GJ/h c/w BFW pumps & related equipment	$23 400 000
2. Solid fuel handling system	475 000
3. Ash handling system; coke-fired case	200 000
Sub-total: Coal-fired	$23 875 000
Sub-total: Coke-fired	$24 075 000
4. Contingency @ 20 percent: Coal-fired	$ 4 775 000
4. Contingency @ 20 percent: Coke-fired	$ 4 815 000
TOTAL: Coal-fired	$28 650 000
TOTAL: Coke-fired	$28 890 000

C. Operating Costs; Coal-Fired Case

1. Fuel

(a) Coal Consumption:

$$\frac{264 \text{ GJ/h X } 24 \text{ h/d X } 330 \text{ d/yr}}{19.211 \text{ MJ/kg A } .78 \text{ X } 1000 \text{ kg/tonne}} = 139\ 540 \text{ tonnes/yr}$$

Cost:

$$\frac{264 \text{ GJ/h X } 24 \text{ X } 330 \text{ X } \$1.896\text{/GJ}}{0.78} = \$\ 5\ 082\ 000\text{/yr}$$

(b) Limestone consumption:

139 540 X .005 (S%) X 1.5 (Ca/S Ratio) X 3.28 (wt Ca/wt S) = 3 440 tonnes/yr

	Cost:	
	3 440 X $45/tonne =	$ 155 000/yr
		$ 5 237 000
2.	Maintenance	
	Equipment base cost: $12 000 000 @ 3 percent	$ 360 000/yr
	Auxiliary base cost: $6 000 000 @ 2 percent	120 000/yr
		$ 480 000/yr
3.	Electrical Power	
	Total load =	2 950 KVA
	Demand charge: 2 950 KVA X $2.30/KVA X 12 months =	$ 81 400/yr
	Energy Charge: 2 950 KVA X 24 X 330 X $.0125/kW-hr =	290 400/yr
		$ 372 000/yr
4.	Operators	
	3 shifts/d	3
	1 swing	1
	1 supervisor	1
		5 Operators
	Cost - 5 X $135/d X 365 d/yr=	$ 246 000/yr
5.	Waste disposal & miscellaneous	$ 125 000/yr
	Solids quantities	19 910 tonnes/yr
	Cost:	
	$\frac{19\ 910\ \text{tonnes}}{12\ \text{tonnes/load}}$ X $100/load	$ 166 000/yr
	Miscellaneous, overhead allocation	75 000/yr
		$ 241 000/yr
	Sub-Total	$ 6 596 000/yr
6.	Contingency @ 10 percent	$ 660 000/yr
	TOTAL	$ 7 236 000/yr

D. Operating Costs; Coke-Fired Case

1. Fuel

Consumption:

$$\frac{264 \text{ GJ/h} \times 24 \text{ h/d} \times 330 \text{ d/yr}}{31.989 \text{ MJ/kg} \times 0.78 \times 1\,000 \text{ kg/tonne}} = 83\,820 \text{ tonnes/yr}$$

Cost:

$$\frac{264 \text{ GJ/h} \times 24 \times 330 \times \$1.175\text{/GJ}}{.78} = \$3\,177\,000\text{/yr}$$

Limestone consumption:

83 820 X .05 (S%) X 5 (Ca/S Ratio)
X 3.28 (wt Ca/wt S) = 68 730 tonnes/yr

Cost:

68 730 tonnes/yr X $45/tonne = $3 093 000/yr

$6 270 000/yr

2. Maintenance

Equipment base cost: $11 800 000 @ 3 percent $ 354 000/yr

Auxiliary base cost: $6 000 000 @ 2% 120 000/yr

$ 474 000/yr

3. Electrical Power

Total load = 2 950 KVA

Demand charge:
2 950 KVA X $2.30/KVA X 12 months = $ 81 400/yr

Energy Charge:
2 950 KVA X 24 X 330 X $.0125/kW-hr = 290 400/yr

$ 372 000/yr

4. Operators

3 shifts/d	3
1 swing	1
1 supervisor	1
	5 Operators

Cost: 5 X $136/d X 365 d/yr = $ 246 000/yr

5. Waste disposal & miscellaneous	
Solids quanitities	80 460 tonnes/yr
Cost:	
80 460 tonnes/yr X $20/tonne	$1 609 000/yr
Miscellaneous, overhead allocation	75 000/yr
	$1 684 000/yr
Sub-Total	$9 046 000/yr
6. Contingency @ 10 percent	$ 905 000/yr
TOTAL	$9 951 000/yr

E. Discussion

At the present time, 264 GJ/h (250 MM BTU/hr) Multi-Solid Fluid Bed Combustors are the largest planned. However, it appears that larger units would be feasible for large thermal in-situ projects. For these types of steam generators there may be merit to a multiple-unit installation concept as they have some operational limitations which could reduce the operating flexibility of the overall project. The turn-down ratio has been estimated at 2:1 which is less than the other units considered and the start-up/shut-down times required are longer. The response to load changes would also be slightly slower.

Economy of scale for larger units would be anticipated particularly regarding the solids fuel and ash handling facilities. The solids fuel and ash handling equipment provided in the cost estimate would be the minimum size normally considered for a plant of this nature. The facility could easily handle two to four times the capacity without any significant increase in costs.

The operating cost analysis indicated that the cost of fuel, as in all the cases, is by far the largest annual cost associated with the steam generators. The unit costs for coal or coke, contained in this report, can at best be described as approximate. It is unlikely that an accurate cost number could be developed until a specific project was in the actual contract negotiation stages. There are many factors that go into determining the price. Several years of lead time planning would likely be required to establish a source, to determine transportation systems, and to design loading, treatment and unloading facilities. Preliminary investigations indicated that transportation costs for the coke or coal would likely constitute a large portion of the total costs. There would be many variations on the transportation methods. Obtaining more definitive data for coal or coke costs could be the subject of extensive investigation, which is beyond the intended scope of this study.

Similarily, detailed costs associated with solid waste disposal are best estimates at this point in time. For instance, it may be possible to find a market for some of the waste ash which would alter the disposal costs significantly.

Wet Air Oxidation

A. Basis for Cost Estimate

The steam generating plant considered in the cost estimate consists of a single unit rated at 264 GJ/h (250 MM BTU/hr). Units of equivalent size have been built and operated in waste treatment applications, and the vendor has a conceptual design of a WAO boiler of this capacity. Portions of the unit would be shop fabricated with final assembly in the field.

The wet air oxidation unit could be one of two basic systems. High pressure air could be used as the O_2 supply to the reactor vessel where the N_2 and other inert gases pass through the reactor and are injected into the formation along with the steam and combustion products. This system would require large air compressors similar to those described later for the downhole and Vapor Therm steam generating systems.

Oxygen, produced by a separate plant could also be used in conjunction with the wet air oxidation steam generator. This system produced a steam/CO_2 mixture for injection to the reservoir. Costs are presented for both systems.

In either case, 100 percent saturated steam would be generated at 14 MPa (2000 psi) and 335°C (635°F). The steam generator efficiency has been estimated at 88 percent.

For the air process, high-pressure compressors would be provided. The total power load of these units would be approximately 17 900 kW (24 000 Hp) of which half would be electric motor driven and half driven by gas engines.

For the oxygen process, an O_2 plant would be provided which uses a combination of molecular sieve and cryogenic processes to obtain 99.5 percent pure O_2. Also associated with the oxygen plant would be large compressors with a total power load of approximately 13 500 kW (18 000 Hp). Due to the nature of the compressors normally used for these plants and for safety reasons, all motors would be electric. The oxygen plant has been rated at roughly 500 tonnes/d.

In all cases the solid-fuel handling facilities provided would be similar to those provided for the Multi-Solid Fluid Bed Combustor.

A continuous blowdown stream would be taken from the reactor vessel of the wet air oxidation unit. The blowdown would contain some solid wastes formed by chemical reactions within the reactor. Two sludge ponds have been provided in the estimate complete with water recovery equipment. It has been assumed that a pond could be dredged every second year and the waste hauled by truck to a nearby landfill site. The amount of sludge would depend somewhat on the feedwater quality.

B. Capital Costs

1.	Wet air oxidation steam generator	
	Shop packaged	$ 9 000 000
	Installation	1 000 000
		$10 000 000
2.	Air compressors: air process	
	3 units	$ 8 700 000
	Installation	7 395 000
		$16 095 000
3.	Oxygen plant: turn-key project	
	500 tonnes/d	$25 000 000
4.	Solid fuel handling facility	$ 475 000
5.	Sludge Ponds	220 000
	Sub-total: Air process	$26 795 000
	Oxygen process	$35 695 000
6.	Contingency @ 20 percent: Air process	$ 5 359 000
	Oxygen process	$ 7 139 000
	TOTAL: Air process	$32 154 000
	Oxygen process	$42 834 000

C. Operating Costs: Air Process, Coal-Fired Case

1. Fuel

(a) Steam generator; consumption, based on vendor material balance

17.388 tonnes/h X 24 h/d X 330 d/yr = 137 700 tonnes/yr

Cost

$$\frac{264\ \text{GJ/h X } 24 \text{ X } 330 \text{ X } \$1.896/\text{GJ}}{0.88} = \$4\ 505\ 000/\text{yr}$$

(b) Limestone: Consumption, based on vendor material balance

1.56 percent of coal = 2 150 tonnes/yr

Cost

2 150 X $45/tonne = $ 97 000/yr

(c) Air compressors: gas engines

8 950 kW X 24 X 330 X 0.2468 m^3/kW-hr = 17.49 X 10^6 m^3/yr

Cost:

17.49 X 10^6 m^3 X 37.257 MJ/m^3 X $2.37/GJ = $1 544 000/yr

$6 147 000/yr

2. Maintenance

Equipment base cost:	$8 700 000 @ 4 percent	$ 348 000/yr
	$5 400 000 @ 3 percent	162 000/yr
Auxiliary base cost:	$6 500 000 @ 2 percent	130 000/yr
		$ 640 000/yr

3. Electrical Power

Total load = 11 000 KVA

Demand charge:
11 000 KVA X $2.30/KVA X 12 months = $ 303 600/yr

Energy Charge:
11 000 KVA X 24 X 330 X $.0125/kW-hr = 1 089 000/yr

$1 393 000/yr

4. Operators

2 @ 1 shift/d	2
1 @ 2 shifts/d	2
2 swing	2
2 supervisors	2
	8 Operators

Cost = 8 X $135/d X 365 d/yr = $ 394 000/yr

5. Waste disposal & miscellaneous

Waste Volume:

Ash = 11.3 percent of coal =	15 560
$CaSO_4$	1 990
	17 550 tonnes/yr

Cost:

$\frac{\text{17 550 tonnes}}{\text{12 tonnes/load}}$ X $100/load = $ 146 000/yr

Miscellaneous	75 000/yr
	$ 221 000/yr
Sub-Total	$8 794 000/yr
6. Contingency @ 10%	$ 879 000/yr
TOTAL	$9 673 000/yr

D. Operating Costs; Air Process, Coke-Fired Case

1. Fuel

(a) Steam generator consumption:

10.445 tonnes/h X 24 h/d X 330 d/yr = 82 730 tonnes/yr

Cost:

$\frac{\text{264 GJ/h X 24 X 330 X \$1.185/GJ}}{.88}$ = $2 816 000/yr

(b) Limestone consumption:

15.6 percent of coke = 12 910 tonnes/yr

Cost:

12 970 X $45/tonne = $ 581 000/yr

(c) Air compressors; gas engines

8 950 kW X 24 X 330 X 0.2468 m³/kW-hr = 17.49×10^6 m^3/yr

Cost:

17.49×10^6 m^3 X 37.257 MJ/m^3 X \$2.37/GJ = \$1 544 000/yr

\$4 941 000/yr

2. Maintenance

Equipment base cost:	\$8 700 000 @ 4 percent	\$ 348 000/yr
	\$5 400 000 @ 3 percent	162 000/yr
Auxiliary base cost:	\$6 500 000 @ 2 percent	130 000/yr
		\$ 640 000/yr

3. Electrical Power

Total load = 11 000 KVA

Demand charge:
11 000 KVA X \$2.30/KVA X 12 months = \$ 303 600/yr

Energy charge:
11 000 KVA X 24 X 330 X \$.0125/kW-hr = 1 089 000/yr

\$1 393 000/yr

4. Operators

2 @ 1 shift/d	2
1 @ 2 shifts/d	2
2 swing	2
2 supervisors	2
	8 Operators

Cost = 8 X \$135/d X 365 d/yr = \$ 394 000/yr

5. Waste disposal & miscellaneous

Waste Volume:

Ash = 9 percent of coke	7 450
$CaSO_4$	17 900
	25 350 tonnes/yr

Cost:

$\frac{\text{25 350 tonnes}}{\text{12 tonnes/load}}$ X \$100/load = \$ 211 000/yr

	Miscellaneous	75 000/yr
		$ 286 000/yr
	Sub-Total	$7 654 000/yr
6.	Contingency @ 10 percent	$ 765 000/yr
	TOTAL	$8 419 000/yr

E. Operating Costs; Oxygen Process, Coal-Fired Case

1. Fuel

(a) Steam generator consumption, based on vendor material balance

17.388 tonnes/h X 24 h/d X 330 d/yr = 137 700 tonnes/yr

Cost:

$\frac{264 \text{ GJ/h} \times 24 \times 330 \times \$1.896/\text{GJ}}{.88}$ =	$4 505 000/yr

(b) Limestone consumption based on vendor material balance

1.56 percent of coal =	2 150 tonnes/yr

Cost:

2 150 X $45/tonne =	$ 97 000/yr
	$4 602 000/yr

2. Maintenance

Equipment base cost: $17 900 000 @ 3 percent	$ 537 000/yr
Auxiliary base cost: $12 500 000 @ 2 percent	250 000/yr
	$ 787 000/yr

3. Electrical Power

Total load =	16 000 KVA
Demand charge: 16 000 KVA X $2.30/KVA X 12 months =	$ 442 000/yr
Energy Charge: 16 000 KVA X 24 X 330 X $.0125/kW-hr =	1 584 000/yr
	$2 026 000/yr

4. Operators

2 @ 1 shift/d	2
1 @ 2 shifts/d	2
2 swing	2
2 supervisors	2
	8 Operators
Cost = 8 X $135/d X 365 d/yr =	$ 394 000/yr

5. Waste disposal & miscellaneous

Waste Volume:	
Ash = 11.3 percent of coal =	15 560
$CaSO_4$	1 990
	17 550 tonnes/yr
Cost:	
$\frac{17\ 550 \text{ tonnes}}{12 \text{ tonnes/load}}$ X $100/load =	$ 146 000/yr
Miscellaneous	75 000/yr
	$ 221 000/yr
Sub-Total	$8 030 000/yr
6. Contingency @ 10 percent	$ 803 000/yr
TOTAL	$8 833 000/yr

F. Operating Costs; Oxygen Process, Coke-Fired Case

1. Fuel

(a) Steam generator consumption

10.445 tonnes/h X 24 h/d X 330 d/yr = 82 730 tonnes/yr

Cost:

$$\frac{264 \text{ GJ/h} \times 24 \times 330 \times \$1.185\text{/GJ}}{0.88} = \$2\ 816\ 000\text{/yr}$$

(b) Limestone consumption

15.6 percent of coke = 12 910 tonnes/yr

Cost:

12 970 X $45/tonne =	$ 581 000/yr
	$3 497 000/yr

2. Maintenance	
Equipment base cost: $17 900 000 @ 3 percent	$ 537 000/yr
Auxiliary base cost: $12 500 000 @ 2 percent	250 000/yr
	$ 787 000/yr
3. Electrical Power	
Total load =	16 000 KVA
Demand charge: 16 000 KVA X $2.30/KVA X 12 months =	$ 442 600/yr
Energy Charge: 16 000 KVA X 24 X 330 X $.0125/kW-hr =	1 584 000/yr
	$2 026 000/yr
4. Operators	
2 @ 1 shift/d	2
1 @ 2 shifts/d	2
2 swing	2
2 supervisors	2
	8 Operators
Cost = 8 X $135/d X 365 d/yr =	$ 394 000/yr
5. Waste disposal & miscellaneous	
Waste Volume:	
Ash = 9 percent of coke =	7 450
$CaSO_4$	17 900
	25 350 tonnes/yr
Cost:	
$\frac{25\ 350\text{ tonnes}}{12\text{ tonnes/load}} \text{ X } \$100\text{/load} =$	$ 211 000/yr
Miscellaneous	75 000/yr
	$ 286 000/yr
Sub-Total	$6 890 000/yr
6. Contingency @ 10 percent	$ 689 000/yr
TOTAL	$7 579 000/yr

G. Discussion

Preliminary cost information indicates that the wet air oxidation systems would be subject to economies of scale for units larger than the 264 GJ/h (250 MM BTU/hr) unit considered in this report. With the exception of the air compression equipment, most of the major items would likely be less expensive per unit of capacity as the size increased. In particular, the oxygen plant could be doubled in size and the capital costs might be 35 - 40 percent higher.

A single wet air oxidation steam generator should not cause any severe operating limitation on a thermal recovery project. In theory, the unit would be capable of an infinite turn-down ratio. In practice, the turn-down ratio may be closer to 10:1 which is much better than the other units considered. The time required for start-up from a cold condition is relatively long as the reactor must be pre-heated with utility steam, but the unit would normally react well to load changes. Another operational advantage would be that the oxidation process takes place at relatively low temperatures without any combustion flame. Therefore, the unit may not be considered a fired boiler, and thus may not be subject to the same regulations as conventional steam generators with regard to the class of operator required, etc.

As can be seen from the operating cost analysis, the coke-fired cases are less expensive than the coal fired case. This differs from the results shown for the multi-solids fluidized bed combustor, due primarily to the much lower quantities of limestone required for the coke case.

Downhole Steam Generators

A. Basis for Cost Estimate

The standard size for a downhole steam generator is approximately 7.4 GJ/h (7.0 MM BTU/hr). For the purpose of the cost estimate, it is assumed 33 of these units would be provided to support a heavy oil thermal project of approximately the same size as the other cases. This results in a total steam heat capacity of 244.2 GJ/h (231 MM BTU/hr) which is slightly lower than the 264 GJ/h (250 MM BTU/hr) capacity of the other systems. The breakdown of total capacity with multiple units allows greater flexibility in operation which could result in a lower total steam facility size. Therefore, this was felt to be a practical equivalent to the other cases.

The downhole steam generators have been designed for installation in the well bore. The concept has been to reduce heat losses associated with piping hot steam through a distribution system and down the well tubing. However, this requires a service rig to pull the steam generator each time problems or changes in operation occur. Service rig time may not be significant on a steam flood recovery process. However, on a cyclic steam (huff-puff) recovery process, the wells would be continuously switched from steam injection to production operations. With a large number of wells on a commercial in-situ project in the Cold Lake region, the service rig costs for installing and withdrawing steam generators may be too high to be practical. Therefore, it was assumed that the downhole steam generators would be installed on the surface adjacent to the well head. This concept has been used in California where downhole steam generators have seen the greatest application to date.

The cost estimate provides for 33 portable downhole generators which could be moved from well to well on an as-needed basis. All effluent from the generator would be injected down the well bore. This includes 100 percent saturated steam and all the combustion gases. The thermal efficiency of the steam generators has been estimated at 98 percent.

The steam generators require high pressure, 14 MPa (2000 psi) feedwater, combustion air and fuel. A central plant has been provided in the cost estimate to feed these fluids to the steam generators. An alternative to this approach might be to provide portable equipment for each steam generator. However, the central facility concept was felt to be more cost effective given the size of the equipment required.

The high pressure combustion air compressors required for this case would be the largest capital item associated with the steam generation system. A preliminary investigation into this equipment resulted in selecting a two stage system which consisted of a low pressure centrifugal compressor feeding a high-pressure reciprocating compressor. Although various alternatives would be possible, it was assumed the centrifugal compressor would be electric motor driven and the reciprocating compressor would be driven by a natural gas fired internal combustion engine. The cost estimate includes three of these units, each rated at approximately 34 percent of the total load. The total rated power of this facility has been estimated at 17 900 kW (24 000 Hp).

High pressure BFW pumps would also be required at the central facility. Two 50 percent capacity plunger pumps similar to those provided for the conventional case have been assumed with a central fuel supply facility. For the crude oil fired case two 50 percent capacity plunger pumps would be provided. For the gas-fired case a high pressure reciprocating compressor has been provided with electrical motor drive. It has been assumed the fuel gas at the lease edge would be delivered at approximately 700 kPa (100 psi). Generally, the natural gas sources in the Cold Lake region have been at low pressure from shallow gas wells.

B. Capital Costs

1. Steam generators; portable	
33 Units @ $50 000	$ 1 650 000
2. Air compressor facility	
3 Units @ $2 900 000	$ 8 700 000
Installation	7 395 000
	$16 095 000
3. BFW pumps	
2 Units @ 500 KVA	$ 405 000
Installation	344 000
	$ 749 000
4. Crude fuel pumps; Crude-fired case	
2 Units @ 25 KVA	$ 26 000
Installation	22 000
	$ 48 000
Natural gas compressor; Gas-fired case	
1 Unit @ 990 KVA	$ 400 000
Installation	250 000
	$ 650 000
Sub-Totals: Crude-fired	$18 547 000
Gas-fired	$19 149 000
5. Contingency @ 20 percent	
Crude-fired	$ 3 709 000
Gas-fired	$ 3 830 000
Totals: Crude-fired	$22 256 000
Gas-fired	$22 979 000

C. Operating Costs; Natural Gas-Fired Case

1. Fuel

(a) Steam generators consumption

$$\frac{244.2 \text{ GJ/h X } 24 \text{ h/d X } 330 \text{ d/yr}}{37.257 \text{ MJ/m}^3 \text{ X } .98} = 52.97 \text{ X } 10^6 \text{ m}^3\text{/yr}$$

Cost:

$$\frac{244.2 \text{ GJ/h X } 24 \text{ X } 330 \text{ X } \$2.37\text{/GJ}}{0.98} = \quad \$4\ 677\ 000\text{/yr}$$

(b) Air compressors; Gas engines consumption

$8\ 950 \text{ kW X } 24 \text{ X } 330 \text{ X } 0.2468 \text{ m}^3\text{/kW-hr} = 17.49 \text{ X } 10^6 \text{ m}^3\text{/yr}$

Cost:

$17.49 \text{ X } 10^6 \text{ m}^3 \text{ X } 37.257 \text{ MJ/m}^3 \text{ X } \$2.37\text{/GJ} =$ $1 544 000

$6 221 000

2. Maintenance

Equipment base cost:	$9 100 000 @ 4 percent	$ 364 000/yr
	$2 100 000 @ 3 percent	63 000/yr
Auxiliary base cost:	$2 585 000 @ 2 percent	52 000/yr
Steam generator moving		198 000/yr
		$ 677 000/yr

3. Electrical Power

Total load = 11 900 KVA

Demand charge:
11 900 KVA X $2.30/KVA X 12 months = $ 328 000/yr

Energy charge:
11 900 KVA X 24 X 330 X $.0125/kW-hr = 1 178 000/yr

$1 506 000/yr

4. Operators

2 for 3 shifts/d	6
2 swing	2
2 supervisors	2
	10 Operators

Cost = 10 X $135/d X 365 d/yr = $ 493 000/yr

5.	Miscellaneous	$ 75 000/yr
	Sub-Total	$8 972 000/yr
6.	Contingency @ 10 percent	$ 897 000/yr
	TOTAL	$9 869 000/yr

D. Operating Costs; Crude-Fired Case

1. Fuel

(a) Steam generators - consumption

$$\frac{244.2 \text{ GJ/h} \times 24 \text{ h/d} \times 330 \text{ d/yr}}{44.889 \text{ MJ/kg} \times .98 \times 970 \text{ kg/m}^3} = 45\ 320 \text{ m}^3\text{/yr}$$

Cost:

$45\ 320 \text{ m}^3 \times \$188.68/\text{m}^3$ = $ 8 551 000

(b) Air compressors - Gas engines

$8\ 950 \text{ kW} \times 24 \times 330 \times 0.2468 \text{ m}^3/\text{kW-hr} = 17.49 \times 10^6 \text{ m}^3/\text{yr}$

Cost:

$17.49 \times 10^6 \text{ m}^3 \times 37.257 \text{ MJ/m}^3 \times \$2.37/\text{GJ} =$ $ 1 544 000

$10 095 000

2. Maintenance

Equipment base cost:	$8 500 000 @ 4 percent	$ 348 000/yr
	$2 100 000 @ 3 percent	63 000/yr
Auxiliary base cost:	$2 585 000 @ 2 percent	52 000/yr
Steam generator moving		198 000/yr
		$ 661 000/yr

3. Electrical Power

Total load = 11 000 KVA

Demand charge:
11 000 KVA X $2.30/KVA X 12 months = $ 303 000/yr

Energy charge:
11 000 KVA X 24 X 330 X $.0125/kW-hr = 1 089 000/yr

$ 1 393 000/yr

4.	Operators	
	2 for 3 shifts/d	6
	2 swing	2
	2 supervisors	2
		10 Operators
	Cost = 10 X $135/d X 365 d/yr =	$ 493 000/yr
5.	Miscellaneous	$ 75 000/yr
	Sub-Total	$12 717 000/yr
6.	Contingency @ 10 percent	$ 1 272 000/yr
	TOTAL	$13 989 000/yr

E. Discussion

To date the downhole steam generators have been fired on gaesous or liquid fuels. Heavy #6 fuel oil has been used successfully although conversion to solid fuels has not been attempted. Development of a solid-fuel firing system does not seem likely in the immediate future.

As in the discussion on conventional steam generators, a combination of waste gases from a large thermal project may be a partial source of low grade fuel. A make-up or balancing fuel would still be required to support the entire steam generating load.

The downhole steam generators have been designed and constructed to inject steam and combustion products into an individual well. Therefore, a very large in-situ thermal project would require many units. The steam generators alone would not be the most expensive component to the facility and because of the design concept, individual units would not likely be fabricated significantly larger. The support facilities would make up the larger portion of the capital costs.

The air compressors assumed in this cost estimate are approaching the largest sizes normally available. Therefore, a project requiring more than 244 GJ/h (231 MM BTU/hr) would not likely benefit significantly from economy of scale. Multiple units would be added to increase the size of the facility.

In-situ thermal projects which do not require 14 MPa (2000 psi) pressure would benefit from somewhat lower operating costs, but until the required pressure is below 7.58 MPa (1100 psi), a significant decrease in capital cost would not be anticipated. This is primarily due to the type of air compressor required to reach the higher pressures. Lower pressure could be obtained with a less expensive machine.

It may be feasible to design a steam generation facility which combines several machines. A co-generation system has been planned where large gas turbines would be used to drive air compressors and the high temperatue exhaust gases from the turbnes would be employed to generate part of the steam directly in a convection section of finned tubes. This system would be similar to heat recovery equipment commonly installed on gas turbines. Steam generation facilities such as these have not been included in the cost estimate.

Vapor Therm Steam Generators

A. Basis for Cost Estimate

The standard size for a Vapor Therm steam generator has been 12.6 GJ/h (12 MM BTU/hr). For the purpose of the cost esimate 20 of these units have been provided in order to support a heavy oil thermal project of approximately the same size as the other cases. This results in a total steam heat capacity of 253 GJ/h (240 MM BTU/hr) which is slightly lower than the 264 GJ/h (250 MM BTU/hr) capacity of the other systems. Similar to the downhole case, the steam generators would not all be located at a central plant but would be installed at various locations throughout the field. This was felt to be a practical equivalent to the larger central steam plant cases.

The Vapor Therm steam generating equipment has not normally been for sale but could be used on a rental or leasing arrangement. Therefore, the capital costs provide for the installation of 20 units and the annual operating costs including the rental fees. Also included in the rental package would be the BFW pumps and crude oil fuel pumps for each individual unit. Combustion air compressors or fuel-gas compressors have been provided as separate capital items.

The Vapor Therm generator would require high pressure boiler feedwater, combustion air, and fuel. The steam generator effluents would be injected down the well bore. This includes 100 percent saturated steam and all combustion gases. The thermal efficiency of the steam generator has been estimated at 95 percent. A small blowdown pit with water draw-off facilities has been assumed in the cost estimate. The exact volume of the blowdown stream would depend on the water and fuel characteristics.

The high pressure combustion air compressors would be provided at a central location. The equipment would be similar to that described in the downhole case. The total rated power of the facility has been estimated at 17 900 kW (24 000 Hp)

For the gas-fired case, a single high pressure reciprocating compressor has been included to supply fuel to the steam generators.

B. Capital Costs

1. Steam generators c/w BFW pumps & crude fuel pump (if required)

20 Units	Annual Rental Fee
Installation	$2 000 000

2. Air compressor facility

3 Units @ $2 900 000	$ 8 700 000
Installation	7 395 000
	$16 095 000

3. Blow down ponds c/w water draw-off $ 50 000

4. Natural gas compressor; gas-fired case

1 Unit @ 990 KVA	$ 400 000
Installation	250 000
	$ 650 000

Sub-Totals:	Gas-fired	$18 800 000
	Crude-fired	$18 150 000

5. Contingency @ 20 percent:

Gas-fired	$ 3 760 000
Crude-fired	$ 3 630 000

Totals:	Gas-fired	$22 560 000
	Crude-fired	$21 780 000

C. Operating Costs - Gas-Fired Case

1. Fuel

(a) Steam generators consumption

$$\frac{253.2 \text{ GJ/h} \times 24 \text{ h/d} \times 330 \text{ d/yr}}{37.257 \text{ MJ/m}^3 \times .95} = 56.66 \times 10^6 \text{ m}^3\text{/yr}$$

Cost:

$$\frac{253.2 \text{ GJ/h} \times 24 \times 330 \times \$2.37\text{/GJ}}{0.95} = \$5\ 003\ 000\text{/yr}$$

(b) Air compressors; Gas engine consumption

8 950 kW X 24 X 330 X 0.2468 m^3/kW-hr = 17.49 X 10^6 m^3/yr

Cost:

17.49 X 10^6 m^3 X 37.257 MJ/m^3 X $2.37/GJ =	$1 544 000
	$6 547 000

2. Maintenance

Equipment base cost: $9 100 000 @ 4 percent	$ 364 000/yr
Auxiliary base cost: $4 585 000 @ 2 percent	92 000/yr
	$ 456 000/yr

3. Electrical Power

Total load =	11 750 KVA
Demand charge: 11 750 KVA X $2.30/KVA X 12 months =	$ 324 000/yr
Energy charge: 11 750 KVA X 24 X 330 X $.0125/kW-hr =	1 163 000/yr
	$1 487 000/yr

4. Operators

2 for 3 shifts/d	6
2 swing	2
2 supervisors	2
	10 Operators
Cost = 10 X $135/d X 365 d/yr =	$ 493 000/yr

5. Waste disposal & miscellaneous

General overhead allocation	$ 75 000/yr
Pump out & clean out of blowdown pit	50 000/yr
	$ 125 000/yr
Sub-Total	$ 9 108 000/yr

6. Contingency @ 10 percent	$ 911 000/yr

7. Rental Fee; Steam generators

20 units @ \$18 000/month X 12 months — \$ 4 320 000/yr

TOTAL — \$14 339 000/yr

D. Operating Costs; Crude-Fired Case

1. Fuel

(a) Steam generators consumption

$$\frac{253.2\ \mathrm{GJ/h} \times 24\ \mathrm{h/d} \times 330\ \mathrm{d/yr}}{44.889\ \mathrm{MJ/kg} \times .95 \times 970\ \mathrm{kg/m^3}} = 48\ 480\ \mathrm{m^3/yr}$$

Cost:

48 480 m^3 X \$188.68/m^3 = — \$ 9 147 000/yr

(b) Air compressors; Gas engines

8 950 kW X 24 X 330 X 0.2468 m^3/kW-hr = 17.49 X 10^6 m^3/yr

Cost:

17.49 X 10^6 m^3 X 37.257 MJ/m^3 X \$2.37/GJ = — \$ 1 544 000

\$10 691 000

2. Maintenance

Equipment base cost: \$8 700 000 @ 4 percent — \$ 348 000/yr

Auxiliary base cost: \$4 585 000 @ 2 percent — 92 000/yr

\$ 440 000/yr

3. Electrical Power

Total load = — 10 800 KVA

Demand charge:
10 800 KVA X \$2.30/KVA X 12 months = — \$ 298 000/yr

Energy charge:
10 800 KVA X 24 X 330 X \$.0125/kW-hr = — 1 069 000/yr

\$ 1 337 000/yr

4. Operators

2 for 3 shifts/d	6
2 swing	2
2 supervisors	2
	10 Operators
Cost = 10 X $135/d X 365 d/yr =	$ 493 000/yr

5. Waste disposal & miscellaneous

General overhead allocation	$ 75 000/yr
Pump out & clean out of blowdown pit	50 000/yr
	$ 125 000/yr
Sub-Total	$13 126 000/yr

6. Contingency @ 10 percent $ 1 313 000/yr

7. Rental Fee:

20 units @ $18 000/month X 12 months	$ 4 320 000/yr
TOTAL	$18 759 000/yr

E. Discussion

To date the Vapor Therm generators have only been fired on liquid fuels although gas should not be a problem. Solid-fuel firing has not been attempted and the generator has not been considered easily adaptable to solid fuel firing. The ash contained in solid fuels would likely be difficult to separate in the quench chamber.

As discussed under the conventional and downhole steam generator systems, a combination of waste gases from a large thermal project may be a partial source of low grade fuel. However, a make-up or balancing fuel would likely be required to support the entire steam generation load.

It may be possible to scale up the design and construction of the Vapor Therm units to large sizes for large in-situ projects. No efforts have been made in this direction to date as the multiple installation concept seems to have been adopted. Because the units are presently leased and not sold, it is unknown what economy of scale cost advantages may be possible.

The central air compression facilities, being very similar to those provided for the downhole case would be subject to the same comments:

- Multiple units would likely be required to increase the capacity of the steam generation facilities. Therefore, significant economy of scale is not anticipated.
- Reduction of the injection pressures required may result in significant capital cost savings along with the associated operating costs.
- A co-generation steam facility may be feasible to increase the overall efficiency of operation, although costs for such a system have not been included.